



MAR 06 2002

OFFSHORE OPERATORS COMMITTEE

March 5, 2002

Attn: Rules Processing Team (RPT)
Department of the Interior, Minerals Management Service; MS 4024
381 Elden Street
Herndon, Virginia 20170-4817

Re: Notice of Proposed Rulemaking
Procedures for Dealing with Sustained Casing Pressure

Gentlemen:

The Offshore Operators Committee (OOC) appreciates this opportunity to provide written comments on the subject proposed rule to amend regulations in Subpart E regarding dealing with sustained casing pressure (SCP) in oil and gas wells on the outer continental shelf (OCS), as provided in the November 9, 2001 Federal Register Notice. The comments provided herein were prepared jointly with the American Petroleum Institute (API).

OOC is an organization of some 110 companies who conduct essentially all of the OCS oil and gas exploration and production activities in the Gulf of Mexico. Comments made on behalf of OOC are submitted without prejudice to any member's right to have or express different or opposing views.

MMS and OOC have a long history of working together on policies dealing with casing pressure. OOC has provided comments numerous times to MMS proposed policies on both sustained and unsustained casing pressure. Historically, the majority of our comments have dealt with the regulatory and procedural aspects of casing pressure. However, we have come to realize that continued efforts from the regulatory approach will not in our opinion be effective from a cost or value added basis and will not reduce risk and improve safety over the current sustained casing pressure practices. Therefore, we now propose taking a technical and risk based approach to answer the following question, "When is pressure on the casing an unacceptable risk?" We envision developing the answer to the question through a three prong approach:

- Provide funding to a third party who is mutually acceptable to both MMS and Industry to perform a risk based study of casing pressure
- Based on the findings of the study, develop an API Recommended Practice (RP) on casing pressure
- Affirm that subsea wellheads designed in accordance with API Spec 17D with the capability to monitor and diagnose casing pressure in the production/tubing analysis pose a lower level of risk than redesigning the wellhead to accommodate monitoring of all casing annuli through the wellhead.

We envision the study and RP to consider the following issues from a technical and risk basis:

- Risk to personnel, equipment, environment
- Differences in casing and wellhead designs
- Differences in pressure source
- Monitoring
- Testing protocols
- Diagnostics
- Remediation
- Documentation

The study and RP would address all types of wells, fixed platform (surface wellhead and surface tree), subsea (subsurface wellhead and subsurface tree) and hybrid (subsurface wellhead, surface wellhead and surface tree), and would address both sustained and unsustained casing pressure. After the RP is completed and adopted by API, it could be incorporated into MMS's regulations similar to the other API RPs that are incorporated by MMS. OOC would continue to work with MMS to establish appropriate reporting procedures by Industry to MMS that are not overly burdensome on either Industry or MMS. We believe that both API and OOC will sponsor and support such an effort to answer the question "When does casing pressure pose an unacceptable risk?"

In order to provide time to perform the study and develop the RP, we request that MMS consider either withdrawing the proposed rulemaking or holding it in abeyance until these efforts can be completed. Until such time as the study and RP can be completed and the RP adopted into regulation, we recommend that MMS current casing pressure policy as expressed in the Letter to Lessees dated January 13, 1994 remain in effect for fixed platform wells and that subsea wells and hybrid wells continue to be handled on a case-by-case basis through the Deepwater Operations Plan (DWOP) process.

Even though we strongly recommend the above approach as being more effective in reducing risk, adding value and appropriately consider the cost and benefits of dealing with casing pressure, we have developed detailed comments on the highly prescriptive regulation proposed in the rulemaking. We have provided alternative prescriptive language for your consideration if you choose to continue with a prescriptive regulation.

Please note that we take serious issue with your determination that the proposed rule is not significant. We believe the cost of implementing the proposed rule will have an economic impact exceeding \$100 MM on an annual basis and that there will be significant costs to lessees or operators; therefore, the rulemaking should be classified as significant and should be reviewed by the Office of Management and Budget under Executive Order 12866. We also believe the

rulemaking should be classified as a major rule under the Small Business Regulatory Enforcement Fairness Act since the economic impact will exceed \$100 MM on an annual basis.

Again, thank you for the opportunity to provide comments on the proposed rule and we appreciate your consideration of these comments. As requested, we are providing three printed copies of our comments. A CD with our comments will be submitted under separate cover. Please feel free to contact the undersigned at (504) 561-2427 or Mr. Steve Brooks, Chairman—OOC Technical Sub-Committee at (504) 561-4753, if you have any questions concerning our comments or wish to discuss them in more detail.

Sincerely,

Allen Verret, P. E.
Executive Director
Offshore Operators Committee

GENERAL COMMENTS

The following is a summary of general concerns and comments expressed by the various OOC members on the proposed rulemaking.

OOC is disappointed that MMS chose to write a highly prescriptive regulation on casing pressure. Over the last several years, as MMS has rewritten the regulations in 30 CFR 250, the regulations have become much more performance based, which is MMS stated goal. Performance based regulations allow both MMS and Industry much more flexibility to manage the issue and encourages the development of new technological and operational solutions rather than to design systems simply to meet the regulations. This is particularly valid for subsea (subsea wellhead and subsea tree) and hybrid wells (subsea wellhead, surface wellhead and surface tree) where the designs of these systems are rapidly evolving.

OOC Proposal

As stated in the cover letter, OOC believes that a highly prescriptive regulatory approach to casing pressure is not the best approach to ensure safe and environmentally sound operations. Although many wells (over 8000) and casing annuli (over 11,000) in the Gulf of Mexico have casing pressure, both sustained and unsustained, there are only 4 documented cases of uncontrolled well flow that have been attributed by MMS to casing pressure. In these incidents, well and equipment damage occurred, but there have been no injuries to personnel and pollution has been limited to a minor occurrence in one incident. All of these incidents occurred prior to the adoption of detailed policies for sustained casing pressure.

The history begs the question of "When is pressure on the casing an unacceptable risk?" This is a question that to date has not been answered from a technical and risk basis. OOC proposes a three-prong approach to establishing regulations for casing pressure. The first is to do a risk based study on casing pressure. The study would be conducted by a third party acceptable to both Industry and MMS. Using the results of the study, an API Recommended Practice on casing pressure would be developed. The following would be considered in the document:

- Risk to personnel, equipment, environment
- Difference in casing and wellhead designs
- Difference in pressure sources
- Monitoring
- Testing protocols
- Diagnostics
- Remediation
- Documentation

In addition, the document would address the different types of wells, fixed platform (surface wellhead and surface tree), subsea (subsurface wellhead and subsurface tree) and hybrid (subsurface wellhead, surface wellhead and surface tree) appropriately. The Recommended Practice could be considered for incorporation into MMS regulations.

GENERAL COMMENTS

One of the major concerns with the proposed regulation is the imposition of monitoring requirements for all annuli in subsea wellheads. This proposed regulation would affect both subsea and hybrid wells. The risk of having annuli that could not be monitored versus having a sealing mechanism that minimized leak paths between the casing strings through the wellhead, was assessed during the development of API Specification 17D, Subsea Wellhead and Christmas Tree Equipment. Industry plans to re-activate the Specification 17D workgroup to review and revise it as needed. As a part of that effort, the group will review the design of the subsea wellhead and re-confirm the current approach wherein some annuli cannot be monitored is safer and more reliable than one wherein all annuli can be monitored.

OOC believes that by taking this three-prong approach to addressing casing pressure, we will be in a better position to answer the question, “When is casing pressure an unacceptable risk?” and turn our attention, efforts and capital resources to addressing the unacceptable risk areas.

Our general comments below are organized as follows, comments on the Preamble, Regulatory Planning and Review, Fixed Platform Wells, Subsea Wells and Hybrid Wells.

In addition, we have attached detailed comments on the proposed regulation and in the event MMS decided to adopt a highly prescriptive regulation, we offer alternative language for your consideration.

Preamble

The preamble to the proposed regulation has several statements that we find to be incorrect or misleading. MMS states “Data gathered by MMS has shown that SCP is most often caused by leaks in the production tubing and tubing connectors.” OOC is unaware of any study that evaluates the root cause of SCP on the 11,000+ annuli with SCP in the GOM. If such a study exists, we request a copy of it. Although the preamble lists several other causes of sustained casing pressure, it fails to mention that pressure charged formations that are not required to be covered by cement is another contributing source. In the case of uncemented formations, the root source would not be due to a leak; therefore, it is inappropriate to characterize all casing pressure as being caused by leaks. Also, if SCP is truly most often caused by leaks in the production tubing and tubing connectors, then monitoring the tubing/production annulus in wells completed with subsea wellheads should be sufficient.

The preamble states, “If left uncontrolled, this SCP represents an ongoing safety hazard and can cause serious or immediate harm or damage to human life, the marine and coastal environment and property.” While we do not disagree that there is an element of risk with SCP and that it is a serious issue that must be appropriately managed, we do not believe that all SCP represents an ongoing safety hazard. We believe that the magnitude and source of the casing pressure must be considered when determining if a safety hazard exists. For example, an annulus having less than 100 psi of SCP may not present the same level of risk as an annulus with full producing reservoir pressure. Further, historical records simply do not support the notion that all SCP represents a safety hazard. If this is a valid premise, we anticipate that there would be a much higher number of reported uncontrolled well flows than the four reported by MMS as being attributable to SCP. It

GENERAL COMMENTS

has been over ten years since an uncontrolled well flow has occurred which has been attributed to SCP. During this period of time, MMS has established a detailed SCP policy. It is also important to note that in the four incidents, property damage was caused, but no personnel injuries occurred and only minor pollution occurred in one incident. The preamble also does not distinguish between the potential consequences for different scenarios. For example, the risk of personnel injury is certainly different for unmanned fixed platforms and subsea wells than for manned facilities.

The proposed regulation also fails to consider the casing design. Wells completed with either subsea wellheads and subsea trees or surface wellheads and surface trees or a combination, have both structural components and pressure containing components that make up the complete casing design. In many cases, the structural casing strings are necessary for the successful drilling of the well, but have no pressure containment purpose once the well reaches total depth. External pressures, in many cases shallow water sands, applied to these components do not adversely impact the pressure containment ability of the well. Pressures that occur within the pressure containing components are safe so long as those pressures are within the design burst or collapse limitations of the system. Imposing the same requirements for monitoring and eliminating sustained pressures on both the structural and pressure containing components is not technically defensible in our opinion.

We believe that all of these conditions, well types and risks should be evaluated to determine when SCP represents an unacceptable safety hazard and then appropriate procedures to monitor, test, and diagnose should be developed. For those cases where SCP represents an unacceptable risk, appropriate remediation should be conducted. By taking a technically sound risk-based approach to SCP, both MMS and the operator will be allowed to focus on SCP when the risk is unacceptable.

MMS states in the preamble that it conservatively estimates that it would cost \$800,000,000 to \$4,000,000,000 to eliminate SCP on all wells currently reported with SCP. MMS goes on to say that they have sought to identify and eliminate SCP in only those cases that represent a hazard and establish a monitoring system for the rest. In the proposed regulation, MMS requires that operators either eliminate the SCP or plug and abandon wells that are non-producing or continuously injecting. No justification is provided that shows that these wells represent a hazard or a hazard greater than a producing well with SCP. Industry conservatively estimates that it would cost \$540,000,000 to \$2,700,000,000 to eliminate or plug and abandon these non-producing wells. Therefore, this change in MMS policy has a tremendous economic impact on Industry with no justification from a risk standpoint. Further, many non-producing wells are future sidetrack candidates. In many cases, these wells will be plugged versus repaired; therefore, the opportunity to sidetrack will be lost. Many reservoirs that can be economically developed by sidetracks cannot be economically developed by new wells; therefore, these reserves will go unrecovered resulting in an economic loss to both MMS and Industry and a resource loss for the United States.

The preamble states that this rulemaking has been designed to further clarify the intended policy and procedures and to include technology that was not being utilized or was not developed in 1994. This rulemaking goes far beyond clarifying the procedures

GENERAL COMMENTS

established in the January 13, 1994 LTL. We agree that there were many misconceptions with the procedures established by the January 13, 1994 LTL and that clarification is warranted. The January 13, 1994 LTL applies primarily to fixed platform wells. The proposed rulemaking vastly changes the way SCP is handled for fixed platform wells and imposes many new conditions. Please see our detailed comments for areas where new conditions have been applied. For example, self-approval by operators of wells meeting the "life of completion" standards have been eliminated and all requests to continue to operate must be approved by MMS. This goes far beyond clarifying a policy and places a substantial burden on both MMS and Industry. It is not clear to Industry why new conditions over and above those in the January 13, 1994 LTL are contemplated in the rulemaking. It appears to Industry that based on the safety record the current policy has been working well and we don't understand the need to change policy. Currently, MMS policies for casing pressure for subsea wells and hybrid wells are being handled through the DWOP process. Again, we are confused over MMS's perceived need to shift to prescriptive regulations versus the DWOP process, especially since these systems are designed to fit the individual development scenario.

Finally, the preamble states that there are two new requirements in the proposed rule; operators transferring leases to another lessee must provide a report on the status of all wells with SCP to both the MMS and the new owner/operator, and second, subsea trees installed after January 1, 2005 must have a method for monitoring all casing annuli for SCP. Although the first new requirement will place additional burden on both MMS and Industry, we don't take exception to this requirement. However, the second requirement has a tremendous impact on Industry. We note that nothing has changed from either a technology development; historical evidence or risk assessment standpoint that indicates that MMS's current policy of waiving the requirement to provide a method for monitoring all casing annuli for SCP on subsea wells should be modified. In fact, Industry believes that the reliability of the subsea wellhead, subsea tree, umbilical and control systems will actually decrease due to the additional leak paths that will have to be introduced to accommodate monitoring additional annuli over and above the tubing/production annulus that is currently be monitored in wells completed with a subsea wellhead. It must be recognized that the entire subsea system will have to be redesigned appropriately to accommodate the additional monitoring requirement. Significant additional costs must be considered for changes to the tree, umbilical and host platform systems. Also, it must be recognized that this impact affects both subsea wells and hybrid wells.

Regulatory Planning and Review

MMS states that the proposed rulemaking is not significant and will not have an effect of \$100 MM or more on the economy. Industry strongly objects to this statement. We believe that the rule is significant and will have an effect of greater than \$100 MM on the economy. We believe the major economic impacts of the rule are as follows:

- The increased monitoring frequency from monthly (currently typically imposed as conditions as approval) to weekly on unmanned platforms and daily on manned platforms will have an economic impact of \$50/per week for every well with SCP. Using MMS' approximately 8000 wells with SCP, the economic impact will be \$400,000 per week or \$20 MM per year.

GENERAL COMMENTS

- The requirement to either eliminate or plug and abandon non-producing wells with SCP is estimated to cost \$540 MM to \$2.7 Billion. This is based on the cost range provided by MMS for well repair and workovers and according to MMS, are conservative estimates. This compares with MMS estimates of \$800 MM to \$4 Billion to eliminate SCP on all wells with SCP. This economic impact is for the repair and workover cost only. It does not take into account the lost opportunities for sidetracks and the loss of reserves in the event that the wells cannot be repaired and are plugged and abandoned. Just meeting this requirement in the proposed rule will have an impact on the economy of greater than \$100 MM.
- MMS estimates that it will cost \$175,000 per well to provide a method to monitor all casings for SCP when subsea wellheads are used. Industry strongly disagrees with this estimate. MMS has not included the cost for redesigning all affected elements of the subsea system that would need modification. These include the subsea wellhead, subsea tree, umbilical, control systems and host platform systems. Further, both subsea wells and hybrid wells utilize subsea wellheads. MMS has not considered any impacts on hybrid wells. Industry conservatively estimates that the cost impact would range from \$3 MM to \$6.5 MM per subsea well for modification to the subsea wellhead, subsea tree, manifold, jumpers, controls, umbilicals and flowlines for an average subsea system installation. This would not include those that are located far from the host facility. Using MMS's estimate of 25 subsea well completions per year, this would be an economic impact of \$75 MM to \$162.5 MM per year. This does not include the impact to hybrid wells. Costs for increased methanol usage, additional interventions, or deferred production have not been included. Even without those increased costs, it is obvious the economic impact would exceed \$100 MM per year.
- MMS has also not included any costs to eliminate any SCP that occurs in wells completed with a subsea wellhead. In the event that MMS required remediation of SCP in a subsea well, one would have to move on a MODU, cut and retrieve and/or perforate the production casing to attempt to bleed and isolate the casing annulus. The trapped casing pressure would then be eliminated in all likelihood by perforating and cement squeezing. The well would then be recompleted. The estimated cost for this operation is \$12 to 18 MM per well. An economic impact greater than \$100 MM would be achieved if nine or more interventions per year were done. This is not unreasonable given the number of wells completed with subsea wellheads.
- For hybrid wells, the total cost to eliminate any SCP could approach the costs of eliminating pressure in a subsea well. In some cases, an isolation packoff assembly could be used or in the event of a tubing leak, the tubing could be pulled and the leaking joints replaced. It is estimated that these types of workovers could be completed for \$2.5 to \$4 MM per incident.

Fixed Platform Wells

GENERAL COMMENTS

Industry believes that it is critical to distinguish between the different types of wells and to not arbitrarily impose the same conditions, restrictions and test methods on all types of wells. For purposes of this rulemaking, we define fixed platform wells as those completed with a surface wellhead and surface tree. This type of well is the one that we have the most experience with and certainly most of the wells currently in the GOM fit into this category. All of the previous policy statements and regulations going back to OCS Order 6 address fixed platform wells. As new policy statements have been issued, the regulations have gotten increasingly more prescriptive, including this proposed rulemaking. However, the historical performance of these wells does not support this approach. Even though there are over 8000 wells with SCP, according to MMS there have been only 4 uncontrolled well incidents that they attribute to SCP. All of these incidents occurred over 10 years ago. We are confused over the need to promulgate extremely prescriptive regulations when the existing policies appear to be working as evidenced by the lack of incidents. We acknowledge that in the past we have worked with MMS on various LTL's and policies with little additional technical work on the risk and hazard issue of sustained casing pressure. We now believe that instead of continuing down a regulatory path with little technical basis that we should take a fresh approach and look at SCP from a technical and risk basis.

As we stated above, and in our detailed comments, the effect on fixed platform wells is significant from both an economic standpoint and from a burden standpoint on both Industry and MMS. We believe that neither Industry nor MMS should commit the manpower it will take to move away from a self approval process to one in which all SCP, no matter its magnitude or source, will have to be submitted to MMS for approval. To just cover the existing wells with SCP, both MMS and Industry will have to process over 154 submittals a week so that MMS can appropriately place them in either Life of Completion status or Fixed Term Status during the first year after promulgation of the proposed regulations. MMS estimates that it will take 2 hours for Industry to submit the results of diagnostic tests, departure requests and supporting information. That adds up to 1000 man-days just for the existing wells. Assuming that it also takes MMS a similar length of time to evaluate and grant or deny the departure, a similar work commitment is required. Then, as SCP is developed on new wells, workovers are performed, or subsequent diagnostic tests are run, more submittals will be generated. We question if there is any benefit to the increased workload placed on MMS and Industry. We also question if the proposed rulemaking actually reduces risk over and above the current policy. We believe it would be more reasonable to determine when SCP actually poses an unacceptable risk and to commit our time, attention and capital resources to those wells.

We also question the rationale between treating producing and non-producing wells differently and do not understand the increase in risk and hazard that non-producing wells pose over producing wells. It is evident that MMS views non producing wells as posing a higher level of risk over producing wells since the SCP is required to be eliminated, the well plugged and abandoned, or put back on production. We suspect that MMS is simply trying to use this regulation as an avenue to accelerate the plugging and abandoning of non-producing wells. However, the proposed approach may be short sighted since these non-producing wells are the avenue through which wells may be side tracked and

GENERAL COMMENTS

reserves developed that could not be economically developed by new wells. Imposing this regulation will lead to more reserves left undeveloped.

Subsea Wells

For purposes of this rulemaking, we define subsea wells as those completed with a subsea wellhead and subsea tree and that flows back to a host facility. These wells may be located in either shallow or deepwater. The subsea trees may be vertical or horizontal. The control systems may be direct hydraulic or an electro/hydraulic system. The well may be located 500 feet from the host facility or 60 miles away. All of these variations indicate that “one size does not fit all” when it comes to subsea systems. Therefore, the promulgation of prescriptive regulations for handling SCP in subsea wells does not appear to be appropriate. Currently, the operator proposes his plans for monitoring, testing, diagnosing and mitigating SCP in the Deepwater Operations Plan (DWOP). We recommend that this practice continue.

The inclusion or adoption of requirements for subsea wells that are similar to those for fixed platform wells does not take into account all of the ways these wells and systems are different. We believe that the implementation of these SCP regulations will lead to significantly higher costs and increased risk, including operational risk. The proposed regulations seem to confuse the subsea wellhead and subsea tree and do not address the umbilical, control system and host facilities. All of these will be impacted by the proposed regulations.

The subsea wellhead is set when the well is drilled. The subsea tree is set when the well is completed. The subsea well may be drilled several years prior to the completion of the well. This is different from fixed platform wells where the wellhead and tree are set (in sequence) at the same time. Therefore, to use the language that “If you install a subsea tree after January 1, 2005, you must provide a method for monitoring all casing annuli for SCP” is a good example of where extending fixed platform well regulations to subsea wells is inappropriate. In order to meet this timeframe, subsea wellheads, and the other systems that could accommodate monitoring, would have to be available today. Subsea wellheads, subsea trees, umbilicals and control systems are not available today to accommodate monitoring; therefore, for many wells, it would be impossible to comply with the proposed regulation when the subsea tree is set after January 1, 2005. Also, due to the long length of time between the installation of the subsea wellhead and subsea tree, the valving and ports added for monitoring may experience a high rate of failure. Workovers to rectify these problems would be necessary and would add to the cost of subsea development.

The fundamental issue to be considered is if risk or hazards are increased or decreased with the ability to monitor all casing annuli through the subsea wellhead. Industry, through their work on developing API Specification 17D, believes that risks and hazards are increased by designing wellheads to accommodate monitoring. Currently casing annuli are isolated by a metal-to-metal seal assembly that is designed for high reliability and to keep wellbore pressure in the wellbore. Due to low fracture gradients and high pore pressures, especially in deepwater, multiple casing shoes need to be isolated from the deeper high pressures. Quite often, this is done with liners that add a further level of protection by placing the liner lap deeper in the well. In some cases, liners are tied back

GENERAL COMMENTS

to the subsea wellhead and seal assembly with a cemented tieback. Thermally induced pressures can be reliably designed for with proper tubular selection and annular fluid design. Industry believes that reliability of the subsea wellhead will be reduced by introducing leak paths through the subsea wellhead. We believe that MMS has not fully considered all of the risks and potential consequences of fundamentally modifying a subsea wellhead that has performed well and has a good track record. It should also be recognized that the annulus between the tubing and production casing is capable of being monitored in subsea wells. We note that no instances of uncontrolled well flow attributed to SCP have occurred from subsea wells.

Although specific prescriptive regulations have not been promulgated in this rulemaking for running diagnostic tests when SCP is discovered, if the annuli are going to be monitored, a method for testing and bleeding off the pressure will have to be provided, similar to the requirement for the tubing/production casing annulus. This is very problematic in subsea wells and will require substantial redesign of the subsea system.

As stated in the rulemaking, the requirement to monitor all casing annuli will “simply make subsea installations conform to the same standards as wells with surface trees”. This statement shows a lack of understanding of the physical differences between fixed platform well system, subsea systems and hybrid well systems. Here are some of the impacts of imposing fixed platform well regulations on subsea wells:

- The manufacture and physical position of the casing hanger to the wellhead is totally different for wells utilizing a surface wellhead versus a subsea wellhead. The configuration difference creates various technical and operational challenges that are not simply resolved with the proposed regulatory changes.
- Current technology of subsea wellhead systems does not provide the ability to monitor all casing annuli. The creation of the external vent port between each of the casing hanger annuli or an internal casing hanger seal monitoring capability would be required to be developed and implemented.
- Any monitoring ports, beyond the added risk of an environmental leak during drilling, completions or production operations, would be susceptible to failure needing repair. Repeated operations to meet the frequent testing for sustained or unsustained casing pressure could lead to failure requiring a workover or for the well to be plugged and abandoned. Added workovers due to the introduction of the increased well complexity would result in added costs, and more importantly, added risk to well control problems, environmental risk and personnel exposure. Even leaving a monitoring valve open for long periods would add the risk of not being sure it would test or close when needed.
- To add a penetration through the subsea wellhead system would require a major revision to API Specification 17D which specifically prohibits the penetrations into a subsea high pressure wellhead housing. The concept of providing multiple penetrations through the wellhead housing to provide access to all the casing annuli will require a dual barrier concept of sealing for the inboard primary seal surface on the external side of the wellhead. Also, redundant, removable and

GENERAL COMMENTS

repairable ROV remote controlled gate valves of full rated pressure will be needed. To enable this annular access valve arrangement creates a new challenge to enable BOP guidance systems and completion guide base frames to be deployed and removed as required.

- Another option to provide monitoring and venting of the casing annuli through each casing hanger into the subsea tree would require significant redesign of the wellhead and subsea tree systems. The technical design, operational review and full scale testing of the system would be required to ensure that production casing pressure could not enter the outer drilling casing annuli. Starting with the current design of casing hangers and subsea trees, it would be very difficult to maintain the dual pressure barrier design. This would be necessary to eliminate the potential and very high risk prospect of production wellbore fluids from entering the outer casing annuli which could lead to a casing failure and potentially an uncontrolled well flow situation.
- The types of fluids that are removed from the tubing/production casing annulus and the outer drilling casing annuli are significantly different from each other. The fluid in the tubing/production annulus is typically a clean, filtered, low to no solids fluid (clear brine packer fluid). The fluid in the outer casing annuli is typically high solid drilling mud that was in use at the time of casing cementing as a trapped fluid below the casing hanger and seal assembly. Traditionally on surface wellheads, the bleeding of the primary production casing annulus is done via a tubing head valve just below the tubing hanger. On a subsea well, a similar capability exists. The clean fluid can be flowed through a dedicated annulus bleed line or via the production flow line. If the outer annulus is bled off through a bleed line, the high solid drilling fluid will quickly, if not immediately, plug the bleed line in the umbilical and thus render the monitoring system useless. Additionally, hydrates are likely to form in the control line if leaks in the system occur which will also render the monitoring system useless.

The interfaces and ability to access all of the casing annuli to monitor and/or perform diagnostic analysis of sustained casing pressure present difficult technical, reliability, and risk issues. System design features need to be formally addressed in technical, operational, cost and loss of production risk evaluations to ensure that the potential for casing failures does not increase. These casing failures would result in increased production environmental risk and significant operational cost, and possible loss of production or the wellbore.

If an operator was required to use a design that allows all of the annuli to be bled into the production flowline, then two key operational risks are now exposed. First, it would be possible for the outer casing string to be exposed to full rated formation pressure. This could be caused by a leak in the valves or control methods used to the control the flow from the annulus to the flowline. With time, pressure gauges will fail and the monitoring system is lost. This creates a scenario where the well is at risk due to the well flowing to the outer annuli undetected. To mitigate this scenario, an additional or dedicated umbilical test line to test the valve closures would be required. Alternatively, an

GENERAL COMMENTS

intervention using either a MODU or ROV would be required any time a pressure sensor failed. Either mitigation would have a considerable financial impact.

A catastrophic failure of the outer casing strings could occur if full formation pressure is applied to them. This could lead to an uncontrolled well flow either to the seafloor or to an underground blowout. In many cases, this would lead to the loss of the well and it would be plugged and abandoned.

Secondly, the industry history of wellbore interventions shows us that approximately 50% of the subsea well interventions are for below mudline activities and 30% are for subsea tree and control system repairs. Most of the below mudline interventions are due to sand control failures. Each time a well is shut in for any reason and then brought back on production, the risk of sand control failure increases. If the production flow line is used to bleed casing pressure by shutting in the production flow, then the risk of a sand control failure increases. Also, the production rate or ultimate reserve recovery from wells that are beginning to produce water are put at higher risk.

The methodology of running diagnostic tests should be carefully considered and not just be an extension of the protocols used for fixed platform wells. The risk of plugging the annulus bleed line should be considered in the test design. The time to bleed off the casing pressure through a control umbilical would be very long due to small diameter of the bleed line. The distance between the subsea well and the host platform must be taken into consideration. The protocols for fixed platform wells call for the casing pressure to be bled to zero (surface pressure). For a subsea well, the casing pressure will be affected by the hydrostatic pressure of the fluid medium filling the bleed line and this pressure would have to be accounted for. The protocol would also need to ensure that the hose jumpers would not collapse by limiting the vented pressure for a casing annulus above the ambient subsea pressure to minimize the collapse pressure of the hose jumpers.

Hybrid Wells

For the purpose of this rulemaking, hybrid wells are defined as those completed with a subsea wellhead, a surface wellhead and a surface tree. A hybrid well may have either one (single bore) casing string or two (dual bore) casing strings brought up and tied back at the surface. Mudline isolation packers may or may not be utilized within the tubing and production casing annulus or between the inner and outer risers. Typically, pressure will be imposed on the tubing/production annulus with nitrogen. The annulus between the inner and outer risers of the dual bore system is filled with a completion fluid. Since hybrid wells are based on utilizing a subsea wellhead, much of the discussion above is applicable to hybrid wells. In addition, since you have casing strings tied back to a surface wellhead, there are additional considerations. Neither MMS nor Industry has an extensive history of evaluating casing pressure in these systems. Since they are custom designed to fit the development scenario, it is difficult to address these systems appropriately as a group. We feel that addressing these systems through the DWOP process is more appropriate than establishing prescriptive regulations.

OOC Proposed Changes to the Proposed Sustained Casing Rule

Proposed Rule	Propose Language	Rational for Change
§ 250.517 Tubing and wellhead equipment. (c) When the tree is installed, you must equip the wellhead so that all annuli can be monitored for sustained pressure. You must not operate a well that has sustained casing pressure (SCP) in any casing annulus unless: (1) You immediately notify the District Supervisor when you first observe SCP in the well; and (2) You obtain permission from the District Supervisor to operate the well as described in § 250.521.	§ 250.517 Tubing and wellhead equipment. You must not operate (produce or inject into) a well that has sustained casing pressure (SCP) in any casing annulus unless: (1) You notify the District Supervisor by telephone, telefax or electronic mail by the close of the next business day when you first observe SCP in the well; and (2) You obtain approval from the District Supervisor to operate the well as described in § 250.521.	<p>1. Please see our detailed comments on equipping the wellhead so that all annuli can be monitored. Not all annuli are used for pressure containment and a distinction should be made to identify those that are structural in nature and those that are primarily pressure containment. The environment that the tubulars are placed in is dynamic and the changing pressure environment was evaluated in the design of the tubulars. This is also considered when a subsea wellhead is chosen that does not allow leak paths to outer casing strings and therefore is not equipped so that all annuli can be monitored for sustained pressure, but is equipped so that the production/tubing annulus is monitored. The successful deployment and use of the current subsea wellhead systems with its annuli monitoring restrictions should be considered in evaluating the necessity of changing the wellhead and increase the potential leak paths merely to monitor additional strings which historically have not caused problems with subsea wells. Also, the other components which make up the subsea well system, including the subsea tree, umbilical, control system, and host facility systems would have to be modified to accommodate monitoring. Since subsea trees are also used for hybrid wells, these wells are also affected. Consideration should be given to only requiring the monitoring of annuli that are available for monitoring. This practice is currently followed in the GOM.</p> <p>2. We recommend defining the word “operate” to mean produce or inject into. In the MMS proposed regulation, the meaning of “operate” is unclear.</p> <p>3. We recommend that you define “immediate” as “by the close of the next business day” and provide a method for the notification.</p> <p>4. We recommend changing the word “permission” to “approval” to be consistent with other regulations.</p> <p>Definitions for the three different types of well configurations need to be included in the regulation for clarity and for ease in distinguishing the requirements for the different well configurations.</p> <p>1. We believe that a clear distinction should be drawn between casing strings that are needed only to drill the well and those that are needed for pressure containment once the well has been</p>
§ 250.518 How does MMS define pressure found in a well? MMS defines pressure found in a well as follows:	§ 250.518 How does MMS define pressure found in a well and how does MMS define fixed platform wells, subsea wells and hybrid wells?	<p>§ 250.518 How does MMS define pressure found in a well?</p> <p>MMS defines pressure found in a well as follows:</p> <p>(a) Unstressed casing pressure is pressure in a well that is self-imposed (e.g. gas-lift pressure, gas or water-injection pressure), or pressure that is</p> <p>(a) Unstressed casing pressure is pressure in a well that is self-imposed (e.g. gas-lift pressure, gas or water-injection pressure), or pressure that is</p>

Proposed Rule	Propose Language	Rational for Change
entirely thermally induced.	entirely thermally induced. Unsustained casing pressure also includes pressure on structural pipe casing strings. Structural pipe casing strings are those casing strings utilized to facilitate the drilling of the well, but are not needed for pressure containment after the well has been drilled.	drilled. The structural pipe casing strings are not designed to contain pressure since that is not their function. Therefore, they should not be treated as equivalent to the casing strings which are needed for pressure containment for the safe operation of a well. It should also be recognized that the source of pressure on structural casing strings is significantly different than the source of pressure on the pressure containing casing strings. The source of pressure on structural casing strings is usually shallow water sands with limited volume. The source of pressure on the pressure containing casing strings may be either a water sand or a productive interval that may have significant volume.
(b) SCP means a pressure that is:	(b) SCP means a pressure in the annulus of the non structural casing strings that is:	1. See comments above.
(1) Measurable at the casinghead of an annulus that rebuilds when bled down;	(1) Measurable at the casinghead of an annulus that rebuilds to the same pressure level when bled down;	2. The well has been designed for pressure containment. Pressure is not a problem so long as it is not in excess of the design parameters with appropriate safety factors.
(2) Not due solely to temperature fluctuations;	(2) Not due solely to temperature fluctuations;	3. The pressure may be due to an un cemented formation, charged zones or gas migration to the surface and may not be a loss of integrity.
(3) Not a pressure that has been applied deliberately; and	(3) Not a pressure that has been applied deliberately; and	
(4) A result of one or more leaks.	(4) A result of one or more losses of seal integrity or uncemented formations.	
	(c) Fixed platform wells are those defined as being completed with a surface wellhead and a surface tree.	Using common definitions will help clarify the rule.
	(d) Subsea wells are those defined as being completed with a subsea wellhead and a subsea tree.	
	(e) Hybrid wells are those defined as being completed with a subsea wellhead, a surface wellhead and a surface tree.	
§ 250.519 What is the MMS policy for the prevention of sustained casing pressure (SCP)?	You must design and maintain your casing, completion, and tubing programs according to the requirements of subparts D, E, and F of this part, to prevent the occurrence of SCP on wells.	The regulations as proposed below are only applicable to those wells that have been defined above as “fixed platform” wells.
§ 250.520 What are the MMS requirements for monitoring casing pressure?	§ 250.520 What are the MMS requirements for monitoring casing pressure in fixed platform wells?	1. “All of your wells” is unclear. The proposed language mirrors the requirement in 250.517.
(a) You must monitor all of your wells after pressure. This includes wells that have never	(a) You must monitor all of your wells after the tree has been installed for casing	Page 2 of 18

Proposed Rule	Proposed Language	Rational for Change
<p>exhibited SCP. You can achieve this by using either a Supervisory Control and Data Acquisition system or equipping each casing annulus so that a pressure gauge can be used. If any casing annulus in your well exhibits SCP for the first time, you must immediately notify MMS and request approval to operate the well as prescribed in § 250.521.</p> <p>If your well... Then you must...</p> <p>(1) Shows no sustained or unsustained casing pressure when checked... Monitor each annulus at least once every 6 months in conjunction with the test of the surface controlled subsurface safety valve to ensure the continued absence of pressure.</p> <p>(2) Exhibits SCP... Monitor the well at least daily on a manned structure and at least weekly on an unmanned structure.</p> <p>(3) Exhibits unsustained casing pressure... Monitor the well at least daily on a manned structure and at least weekly on an unmanned structure.</p> <p>(4) Is part of a nonconventional (tension leg platform, SPAR, etc) or subsea (wet tree) development... Monitor the well according to § 250.529.</p>	<p>pressure. This includes wells that have never exhibited SCP. You can achieve this by using either a Supervisory Control and Data Acquisition system or equipping each casing annulus so that a pressure gauge can be used. If any casing annulus in your well exhibits SCP for the first time, you must notify the District Supervisor by telephone, telefax or electronic mail by the close of the next business day and request approval to operate the well as prescribed in § 250.521.</p> <p>If your well... Then you must...</p> <p>(1) Shows no sustained or unsustained casing pressure when checked... Monitor each annulus at least once every 6 months.</p> <p>(2) Exhibits SCP... Monitor the well at least monthly on either a manned structure or unmanned structure.</p> <p>(3) Exhibits unsustained casing pressure... Monitor the well at least monthly on either a manned structure or unmanned structure.</p> <p>(4) Is part of a nonconventional (tension leg platform, SPAR, etc) or subsea (wet tree) development... Monitor the well according to § 250.529.</p>	<p>3. There is no need to tie the monitoring of the annulus with the testing of the SCSSV. The timing of the test should be the operator's preference.</p> <p>4. The current GOM policy on casing pressure, 1994 LTL does not establish monitoring frequencies. In conditions of approval for continuing operations with SCP, MMS establishes a monitoring frequency. For wells that are self-approved by the operator, the operator establishes a monitoring frequency. The typical monitoring frequency used is monthly monitoring. Monthly monitoring also corresponds with the last monitoring frequency established by MMS policy in the 1991 LTL. Monitoring the wells on a daily basis on a manned structure and on a weekly basis on an unmanned structure is overly burdensome. SCP typically does not vary significantly on a daily or weekly basis. We have enclosed a graph from one operator's experience with a large number of wells (76 annuli with SCP) that demonstrates that there is little variance in SCP from month to month and that monitoring on a monthly basis is sufficient.</p> <p>The proposed increased monitoring requirements for unmanned platforms will require four times the amount of manpower, boat and helicopter transportation than is currently required since monthly SCP monitoring can be done in conjunction with most MMS monthly compliance checks. Increasing the monitoring frequency on manned platforms will require increased manpower. The cost impact of the increased monitoring frequency is roughly estimated at an additional \$50/well with SCP per week. For 8,000 wells with SCP on the OCS, this translates to an additional cost of \$400,000 per week or \$20,000,000 per year to industry for no perceived benefit.</p> <p>The additional transportation and monitoring requirements will expose personnel to an unnecessary risk of accident and injury. This risk involves boat transfers by swing ropes, helicopter transfers and back fatigue that results from working around short and somewhat difficult casing decks that exists on some platforms. Exposing personnel to this additional risk is not justified.</p>

Proposed Rule	Propose Language	Rational for Change
		<p>If the proposed daily or weekly monitoring is in jeopardy of being accomplished in the field due to logistical, weather or other reasons, waiver requests will be have to be generated and submitted to MMS for approval. This is burdensome on both Industry and MMS with no perceived benefits.</p> <p>The notion of installing SCADA on all wells with SCP is not a reasonable alternative due to significant installation and maintenance costs. The cost to install SCADA on all well annuli with SCP and have it communicate the data real-time is between \$2,000 and \$12,000 per annulus. Considering the number of wells on the OCS that currently do not have SCADA installed, this cost would be significant.</p>
		<p>Monitoring on a monthly basis is also a more efficient use of the platform operating personnel time. The more time the platform operating personnel spend monitoring casing pressure, including traveling to and from unmanned platforms, the less time they have to spend on other safety and operating issues; therefore, to ensure these areas are adequately covered, additional personnel may be needed which would be an economic impact. We believe that adopting the MMS proposed monitoring frequencies will lead to increased downtime (and reduced royalty income) as operators will be unable to respond in a timely manner to facility upsets and well shut-ins due to the additional time required to perform these proposed SCP monitoring requirements unless additional operational personnel are added.</p> <p>See comments above on changing “permission” to “approval”. This section is only applicable to those wells classified as “fixed platform” wells.</p>
§ 250.521 How do I obtain permission to operate with SCP?	§ 250.521 How do I obtain approval to operate a fixed platform well with SCP?	<p>1. See comments above on defining “immediate”, and changing “permission” to “approval”.</p> <p>2. We recommend the continuation of the “self approvals” for wells that meet the Life of Completion criteria. Retaining the self approval provisions reduces burdensome paperwork and reporting procedures by both Industry and MMS. MMS states that there are over 8,000 wells with SCP in the GOM. Therefore, MMS and Industry will have to process approximately 154 requests a week during the first year the regulation is in effect to bring these wells into compliance with the regulation which would be extremely burdensome on both MMS and Industry. By retaining self approval, MMS and</p> <p>(a) When you first determine that a well exhibits SCP in one or more casing annulus, you must notify the District Supervisor by telephone, telefax or electronic mail by the close of the next business day. You must then conduct a diagnostic test of the casing pressure in all annuli as required in § 250.527. To obtain approval to operate the well with SCP that does not qualify for a Life of Completion status as outlined in § 250.525, you must then submit the diagnostic test results along with an approval request to MMS within 45working days of the date of the test. You must submit pressure information on each annulus in</p>

Proposed Rule	Propose Language	Rational for Change
<p>the well, because any MMS approval to operate a well that has SCP is granted for the entire well.</p> <p>(b) If your well qualifies for a Life of Completion approval, the results of the diagnostic test must be retained on the platform or in the lessee's field office nearest the OCS facility for review by MMS.</p>	<p>3. Submitting the diagnostic test results along with an approval request within 10 working days is not feasible. In some cases, it may be a week after the test is run before all of the results can be transported from offshore to onshore. Once the information gets to the shorebase, it still must be sent to the operations office for analysis. The entire 10 day allowed in the proposed rule may have elapsed before the test results reach the engineer's desk. The engineer then has to analyze the test results and prepare the approval request. Then, internal approval must be obtained prior to sending the information along with the request to MMS. 45 days is the time allotted to operators for the filing of MER's and MPR's which have requires similar information to be submitted as that for SCP approval requests.</p> <p>4. The proposed 250.517(c) is clear that wells may be produced with sustained casing pressure; therefore, a departure from the regulation is not required. The term "departure request" should be changed to "approval request".</p> <p>(b) Your approval request must include all of the following.</p> <p>(1) A request for a departure from the requirement that you must not operate a well that has SCP in any casing annulus (30 CFR 250.517(c)).</p> <p>(2) A summary containing information about you and your facility, such as: operator name, address, lease, areablock, facility type and whether it is manned or unmanned, and the number of wells on the facility. The summary should also give the well particulars, such as well name, API number, well status, current well production data, and current shut-in and flowing tubing pressures.</p> <p>(3) A current wellbore schematic with all tubing, cementing, and casing data including: size, weight and grade, minimum internal yield pressure (MIYP) of each string, and depths of each tubing and casing string. This information is only required for your initial submittal on each well and following</p>	<p>Industry would be able to focus their efforts on those wells which pose additional risks. This process has worked well since MMS adopted the self approved category in 1994 and we believe it should be continued.</p> <p>1. 30 CFR 250.517(c) is very clear that you are allowed to produce wells with SCP so long as you meet the requirements stated in the regulation. No departure is needed.</p> <p>(b) Your approval request for wells which do not qualify for a Life of Completion status as outlined in § 250.525 must include all of the following.</p> <p>(1) A request for approval to continue to produce a well that has SCP in any casing annulus in accordance with 30 CFR 250.517(c).</p>

Proposed Rule	Propose Language	Rational for Change
<p>a major workover or sidetrack procedure which changes the wellbore.</p> <p>(4) The casing pressure on each annulus (including those with zero pressure before diagnostic testing); percent of internal yield pressure; origin of pressure, if known; any known casing damage or wear; and any known cementing problems.</p> <p>(5) A complete record of the diagnostic test, conducted as required by § 250.527.</p> <p>(6) Any specific operational information that is needed to explain unusual occurrences, such as a large increase or decrease in casing pressure(s) from the previous report, presence of oil in the fluids bled, pressures imposed on production casings, and delays during diagnostic testing due to weather or equipment failure.</p>	<p>§ 250.522 What if I believe my well exhibits unsustained casing pressure (self-imposed or thermally induced)?</p> <p>(a) If you believe that the pressure appearing on a well is self-imposed (e.g., gas-lift pressure, gas or water-injection pressure), you must contact MMS for instructions on providing documentation for the well.</p> <p>(b) If you believe that the pressure appearing on a new well or new completion is entirely thermally induced, you may conduct a shut-in diagnostic test for this test, you must shut in the well and record the fall of the pressure. If pressure falls to zero, this diagnostic test is sufficient, and no further notifications or submittals to MMS are necessary. You must retain the results of this test on the platform.</p>	<p>This section is only applicable to wells classified as “fixed platform” wells.</p> <p>(a) If the pressure appearing on a well is self-imposed (e.g., gas-lift pressure, gas or water-injection pressure), you must retain documentation on the platform or in the lessee’s field office nearest the OCS facility for review by MMS of the self imposed pressure..</p> <p>(b) If you believe that the pressure appearing on a new well or new completion is entirely thermally induced, you may conduct a shut-in diagnostic test for this test, you must shut in the well and record the fall of the pressure. If pressure falls to zero, this diagnostic test is sufficient, and no further notifications or submittals to MMS are necessary. You must retain the results of this test on the platform or in the lessee’s field office nearest the OCS facility for review by MMS.. Alternatively, with thoroughly stabilized pressure and temperature conditions during production operations, the lessee may bleed down the affected casing(s) through a $\frac{1}{2}$-inch needle or $\frac{1}{2}$-inch ball valve approximately 15-20 percent, and obtain a 24-hour chart which shows that the pressure at the end of the following</p> <p>This section is only applicable to wells classified as “fixed platform” wells.</p> <p>1. You will know if you are self-imposing pressure.</p> <p>2. MMS is already notified of the status of the well if it is being gas lifted, used for injection, etc; therefore, further notification is not needed. Retaining documentation on the platform of the self-imposed pressures is consistent with MMS’s proposal for thermally induced pressures.</p> <p>1. The regulations only identifies a limited testing protocol and may eliminate through its prescriptiveness other diagnostic tests that may be suitable and eliminate the need for shutting in production. Other suitable test methods include predictive models that can shorten the time required for the test.</p> <p>2. It can take a very long time for the pressure to fall to zero; therefore, a pressure near zero should be adequate to show that it is thermally induced.</p> <p>3. Retains the test procedure from the 1994, LTL.</p>

Proposed Rule	Propose Language	Rational for Change
	<p>24-hour period is essentially the same as the bleeddown pressure at the start of the 24-hour period while production remains at a stabilized rate. If you want to utilize another alternate diagnostic test, including predictive modeling, the procedure must be submitted to the District Supervisor for approval.</p> <p>§ 250.523 How will MMS respond to my request for a departure to operate my well with SCP?</p>	<p>§ 250.523 How will the District Supervisor respond to my approval request to operate my fixed platform, subsea or hybrid well with SCP?</p> <p>Your request for a departure to operate your well with SCP will result in one of the results in the following table:</p> <p>If MMS... Then you must...</p> <p>(a) Denies your request... Follow the procedures outlined in § 250.524.</p> <p>(b) Places your well in “life of completion” status... Follow the procedures in § 250.525. This means that you have obtained a departure which allows you to operate the well as long as the sustained pressure conditions do not increase more than 200 psig. MMS normally grants this type of departure when the SCP is less than 20 percent of the MIYP, and bleeds to zero for all annuli.</p> <p>(c) Places your well in “fixed term” status... Follow the procedures outlined in § 250.526. This means that you have obtained a departure that allows you to operate the well for a fixed term, usually 1 year. MMS normally grants this type of departure when the SCP bleeds to zero for all annuli, but the SCP is greater than or equal to 20 percent of the MIYP for one or more annuli.</p> <p>1. Clarifies who within MMS will respond to an approval request. 2. See discussion above on approval versus departure. 3. The Life of Completion and Fixed Term status is applicable to all well types.</p> <p>1. See discussion above on approval versus departure and produce versus operate.</p> <p>2. As discussed above, we believe that wells that qualify for “life of completion” status should be self-approved; therefore, no approval request will be sent to MMS for approval.</p>

Proposed Rule	Propose Language	Rational for Change
§ 250.524 What if MMS denies my departure request or cancels an existing departure?	§ 250.524 What if the District Supervisor denies my approval request or cancels an existing approval?	<p>1. Clarifies who within MMS can deny or cancel an approval. 2. See comments above on approval versus departure.</p>
(a) When MMS denies a departure request for cause, we will issue a certified mail denial letter. Within 30 days after you receive the denial letter, you must submit a detailed procedure for remediation of the SCP on Form MMS-124 to the applicable District Supervisor. Unless otherwise directed, you must begin remediation operations within 30 days of the District Supervisor's approval of your remediation procedure.	<p>(a) When MMS denies a an approval request for cause, we will issue a certified mail denial letter. Within 30 days after you receive the denial letter, you must submit a detailed procedure for remediation of the SCP to the applicable District Supervisor. Unless otherwise approved, you must begin remediation operations within the timeframe approved by the District Supervisor.</p> <p>(b) MMS may rescind any departure approval and require you to take corrective measures if casing pressure conditions deteriorate or present a hazard to personnel, the environment, the platform, or the producing formation. Should conditions dictate, MMS can order the immediate shut-in of the well.</p> <p>(c) You may appeal a departure request denial as stated in 30 CFR 250.104. However, the filing of an appeal will not suspend the requirement for your compliance with the decision.</p>	<p>1. See comments above on approval versus departure.</p> <p>2. Reference to Form MMS 124 (Sundry Notice) should be removed since not all remediation procedures require the filing of a Sundry Notice as outlined in 30 CFR 250, Subparts F and G.</p> <p>3. The timeframe for when remediation must begin should be left to the discretion of the District Supervisor and not be an artificially set timeframe for all cases. The District Supervisor should set a suitable timeframe for the remediation to commence taking into consideration the associated risk presented by SCP and the consequence of an undesirable event along with the consideration of rig availability and other similar factors.</p> <p>1. Clarifies who within MMS can rescind an approval. 2. See discussion above on approval versus departure.</p> <p>(b) The District Supervisor may rescind any approval and require you to take corrective measures if casing pressure conditions deteriorate or present a hazard to personnel, the environment, the platform, or the producing formation. Should conditions dictate, the District Supervisor can order the immediate shut-in of the well.</p> <p>(c) You may appeal an approval request denial as stated in 30 CFR 250.104. Within 30 days of a decision by the Director to uphold the District Supervisor's decision, you shall initiate the actions required by the District Supervisor.</p>
§ 250.525 What if MMS places the well in a “life of completion” departure status?	§ 250.525 What if the fixed platform well meets a “life of completion” approval status?	<p>1. See discussion above on approval versus departure.</p> <p>2. We believe that wells that meet the “life of completion” criteria should be self approved by the operator. MMS should not have to approve this status.</p> <p>1. See discussion above on approval versus departure.</p> <p>2. See discussion above on approval versus departure.</p> <p>3. This section is only applicable to fixed platform wells.</p>
(a) If MMS places your well in a “life of completion” departure status, you must still conduct monitoring and subsequent diagnostic tests. You are not required, however, to submit the results of your diagnostic tests to MMS as long as your well remains in this status. Instead, the results of the diagnostic tests must be kept at your field office	(a) If your well meets a “life of completion” approval status, you must still conduct monitoring and subsequent diagnostic tests. You are not required, however, to submit the results of your diagnostic tests to the District Supervisor as long as your well remains in this status. Instead, the results of the diagnostic tests must be kept at your	<p>1. See discussion above.</p> <p>2. See discussion above.</p> <p>3. This section is only applicable to fixed platform wells.</p>

Proposed Rule	Propose Language	Rational for Change
nearest the OCS facility.		
(b) You must conduct diagnostic tests annually. The test must be conducted sooner if your well monitoring shows that the pressure in any annulus has increased more than 200 psig over the pressure measured during the previous diagnostic test. Each time you conduct a diagnostic test, the pressures recorded become the benchmark pressures, and they determine the need for the next diagnostic test.	<p>(b) You must conduct diagnostic tests if your well monitoring shows that the pressure in any annulus has increased more than 200 psig over the pressure measured during the previous diagnostic test. Each time you conduct a diagnostic test, the pressures recorded become the benchmark pressures, and they determine the need for the next diagnostic test.</p> <p>(c) The well remains in the “life-of-completion” status as long as the diagnostic test pressure is less than 20 percent of the MIYP of each of the evaluated casings and bleeds to zero through a $\frac{1}{2}$-inch needle valve within 24 hours for all casing annuli in the well. If any diagnostic test fails to meet these criteria, the well is no longer in the “life-of-completion” status. You must then submit a request including the diagnostic information for approval of a “fixed-term” departure.</p>	<p>1. Arbitrarily conducting diagnostic tests annually when the pressure has not significantly changed is not needed. Running diagnostic tests may exacerbate the condition causing the SCP. Further communication and/or the possibility of flow from the casing are not typical of wells with low, static casing pressure. The probability of creating higher pressures and casing flow problems is much more likely with the routine bleed-offs associated with diagnostic tests. Diagnostic tests should only be run when conditions indicate that the pressure is not stable, and is increasing.</p> <p>1. There have been problems and safety concerns with attempting to bleed down through a $\frac{1}{2}$ inch needle valve. These problems include plugging through the small “port/seat” of this size needle valve. Therefore, the operator should have the flexibility to use either a needle valve or a ball valve.</p> <p>2. Clarifies who within MMS to send the approval request to.</p>
§ 250.526 What if MMS places the well in a “fixed-term” departure status?	<p>(c) The well remains in the “life-of-completion” status as long as the diagnostic test pressure is less than 20 percent of the MIYP of each of the evaluated casings and bleeds to zero through a $\frac{1}{2}$-inch needle valve within 24 hours for all casing annuli in the well. If any diagnostic test fails to meet these criteria, the well is no longer in the “life-of-completion” status. You must then submit a request including the diagnostic information for approval of a “fixed-term” departure.</p> <p>§ 250.526 What if the District Supervisor places the fixed platform well in a “fixed-term” approval status?</p>	<p>1. Clarifies who within MMS is taking the action.</p> <p>2. This section is only applicable to fixed platform wells.</p>
	<p>(a) If MMS places your well in a “fixed-term” status, you must still conduct monitoring and subsequent diagnostic tests. Your “fixed-term” status allows you to operate your well with SCP for a length of time determined by MMS. This fixed term is usually 1 year.</p> <p>(b) You must perform a new diagnostic test and submit a request for a new departure prior to the expiration of the term of your current departure. The test must be conducted sooner if your well monitoring shows that the pressure in any annulus has increased more than 200 psig over that measured during the previous diagnostic test. If any annuli fail to bleed to zero through a $\frac{1}{2}$-inch needle valve within 24 hours, you must notify MMS immediately.</p>	<p>1. Clarifies who within MMS is taking the action.</p> <p>1. If the District Supervisor places your well in a “fixed-term” status, you must still conduct monitoring and subsequent diagnostic tests. Your “fixed-term” status allows you to operate your well with SCP for a length of time determined by the District Supervisor. This fixed term is usually 1 year.</p> <p>1. Prior to the expiration of the term of the current approval, you must submit a new approval request and if your well monitoring shows that the pressure in any annulus has increased more than 200 psig over that measured during the previous diagnostic test, then a new diagnostic test has to be submitted with the request. If any annuli fail to bleed to zero through a $\frac{1}{2}$-inch needle valve or $\frac{1}{2}$-inch ball valve within 24 hours, you must notify the District Supervisor by the end of the next business day.</p> <p>1. Arbitrarily conducting diagnostic tests annually when the pressure has not significantly changed is not needed. Running diagnostic tests may exacerbate the condition causing the SCP. Further communication and/or the possibility of flow from the casing are not typical of wells with low, static casing pressure. The probability of creating higher pressures and casing flow problems is much more likely with the routine bleed-offs associated with diagnostic tests. Diagnostic tests should only be run when conditions indicate that the pressure is not stable, and is increasing.</p> <p>2. See discussion above regarding bleed down valves.</p>

Proposed Rule	Propose Language	Rational for Change
		<p>3. Clarifies whom to notify within MMS.</p> <p>(c) If all casing pressures fall to pressures that are below 20 percent of the MIYP of their respective casing, you may perform a new diagnostic test and submit the results to the District Supervisor with a “life of completion” departure based on the results of the diagnostic test.</p>
	<p>§ 250.527 How must I conduct my diagnostic test?</p> <p>(a) When you determine that any casing annulus in a well requires a diagnostic test, you must bleed the pressure from all casing annuli exhibiting SCP in that well, unless MMS specifically directs otherwise.</p> <p>(b) You must not bleed down the casing(s) of wells with SCP, except to conduct required and documented diagnostic tests.</p> <p>(c) You must record the initial pressures on all annuli of the well before bleed-down. You must then record both bleed-down and buildup pressures graphically or tabularly in at least 1-hour increments for each casing annulus in the wellbore. The graphical or tabular pressure response must be recorded and analyzed to detect possible communication between annuli.</p> <p>(d) You must bleed down the pressure to zero psig in each annulus through a $\frac{1}{2}$-inch needle valve. You must bleed down and build up each annulus separately, while monitoring the adjacent annuli. If the bleed-down takes less than 1 hour, you may simply note the amount of time taken. You must record the rate of buildup of each annulus for the 24-hour period immediately following the bleed-down. During the bleed-down of the production casing, the tubing pressure must be recorded.</p> <p>(e) If you recover fluid during the bleed-down, you</p>	<p>1. We believe that wells in “life of completion” status should be self-approved. We agree that if a well is changing status, MMS should be informed of the change so their records can be complete.</p> <p>§ 250.527 How must I conduct my SCP diagnostic test on a fixed platform well?</p> <p>(a) When you determine that any casing annulus in a well requires a diagnostic test, you must bleed the pressure from all casing annuli exhibiting SCP in that well, unless you request and the District Supervisor grants an alternate test procedure.</p> <p>1. Clarify that this is for SCP, not self-imposed or thermal. 2. This section is only applicable to fixed platform wells.</p> <p>1. The operator should request and receive approval for an alternate test procedure. The proposed regulation is a very prescriptive approach that limits and directs the use of certain methods. The operator, who is knowledgeable of the hardware and facilities being addressed, should be allowed to design an appropriate test. The rule as proposed will limit creative and efficient use of available and proven technology and hardware.</p> <p>1. Clarifies the requirement.</p> <p>(c) You must record the initial pressures on all annuli of the well before bleed-down. You must then record both bleed-down and buildup pressures graphically or tabularly in minimum 1-hour increments for each casing annulus in the wellbore. The graphical or tabular pressure response must be recorded and analyzed to detect possible communication between annuli.</p> <p>(d) You must bleed down the pressure to zero psig, unless another minimum pressure is approved by the District Supervisor, in each annulus through a $\frac{1}{2}$-inch needle valve or $\frac{1}{2}$-inch ball valve. You must bleed down and build up each annulus separately, while monitoring the adjacent annuli. If the bleed-down takes less than 1 hour, you may simply note the amount of time taken. You must record the rate of buildup of each annulus for the 24-hour period immediately following the bleed-down. During the bleed-down of the production casing, the tubing pressure must be recorded.</p> <p>1. Pressure recording and indication hardware are most accurate in the mid scale and bleeding down to “zero” may not be desirable or practical. The operator should have the option of requesting approval from the District Supervisor to stop the test at a pressure greater than zero.</p> <p>2. Please see discussion above concerning bleed down valves.</p> <p>3. These guidelines are quite prescriptive and may limit both the hardware deployed or the operators experience and practices.</p> <p>1. Limiting the total bleed down time, including waiting time to</p>

Proposed Rule	Propose Language	Rational for Change
must record the type and amount. You should conduct bleed-down to minimize the removal of liquids from the annulus. This does not mean that you must necessarily stop the bleed-down when you encounter liquid. Stopping the bleed-down to wait for gas to percolate is permitted, even though this may lead to longer bleed-down times. However, you must document any such “waiting times,” preferably with an annotated pressure chart. The total time for a bleed-down, including those waiting periods, must not exceed 24 hours. After the diagnostic test, you must replace the total volume of any removed liquids with a fluid of equal or greater density.	<p>you must record the type and amount. You should conduct bleed-down to minimize the removal of liquids from the annulus. This does not mean that you must necessarily stop the bleed-down when you encounter liquid. Stopping the bleed-down to wait for gas to percolate is permitted, even though this may lead to longer bleed-down times.</p> <p>However, you must document any such “waiting times,” preferably with an annotated pressure chart. After the diagnostic test, if you deem necessary, the casing can be returned to the pressure on the casing recorded prior to the test using an appropriate liquid in order to reduce fluid flow through the leak path</p> <p>(f) You do not need to diagnose gas-lift pressure(s) caused by active gas- or water-injection as SCP. However, you must monitor gas-lift pressure(s) during the diagnostic test to confirm that there is no communication with another annulus. You must not close subsurface safety valves during a diagnostic test.</p> <p>(g) You must retain complete casing pressure and diagnostics data on each well for a period of 2 years. Casing pressure records must be maintained at the lessee's field office nearest the OCS facility for review by MMS.</p>	<p>24 hours is problematic for unmanned facilities. Personnel will either have to remain on the platform, often with no facilities for personnel, or come back to the facility within 24 hours. This is very burdensome on the operator. The bleed and wait rules should be provided as guidelines only and not as specific protocol needs. Time limits should be tied to good practices and successful past practices.</p> <p>2. It is not always possible or necessary to replace the total liquid volume removed with a liquid of equal or greater density than that removed. This is particularly true on unmanned platforms where pump capacity is limited. Also, the pumping fluid into the annulus may cause greater fluid flow through the leak path.</p> <p>3. It is not always desirable to replace fluid bled from an annulus. Thermal heating of fluid re-injected into the annulus may cause pressures that exceed the design limits of the completion components. (This is especially true in offshore Alaska waters).</p>
§ 250.528 When must I conduct a diagnostic test?	§ 250.528 When must I conduct a diagnostic test on a fixed platform well?	This section is only applicable to fixed platform wells.
Your requirements to conduct diagnostic tests are contained in § 250.521 through § 250.530. The following table summarizes your requirements and directs you to the section with full information:	Your requirements to conduct diagnostic tests are contained in § 250.521 through § 250.530. The following table summarizes your requirements and directs you to the section with full information:	
If... Then...	If... Then...	See comments in the appropriate section
(a) You initially detect SCP in any annulus of the well...	(a) You initially detect SCP in any annulus of the well...	

Proposed Rule	Propose Language	Rational for Change
An initial diagnostic test must be performed after MMS has been notified (see § 250.521). (b) Your well is in a “life of completion” departure status... A diagnostic test must be performed annually (see § 250.525).	An initial diagnostic test must be performed after the District Supervisor has been notified (see § 250.521). (c) Your well is in a “life-of-completion” departure status, and the pressure in any annulus reaches a pressure 200 psig greater than the pressure measured during the previous diagnostic test... A diagnostic test is required immediately (see § 250.525). (d) Your well is in a “fixed term” departure status... You must perform a new diagnostic test and request a new departure prior to the expiration of the existing departure (see § 250.526). (e) Your well is in a “fixed-term” departure status and the pressure in any annulus is at least 200 psig greater than the pressure measured during the previous diagnostic test... A diagnostic test is required immediately (see § 250.526). (f) You conduct workover operations on the well... You must conduct a new diagnostic and submit a departure request if any pressure remains after the workover (see § 250.532).	(c) Your well is in a “life-of-completion” departure status, and the pressure in any annulus reaches a pressure 200 psig greater than the pressure measured during the previous diagnostic test... A diagnostic test is required to begin as soon as practical (see § 250.525). (d) Your well is in a “fixed term” departure status... You must perform a new diagnostic test and request a new departure prior to the expiration of the existing departure (see § 250.526). (e) Your well is in a “fixed-term” departure status and the pressure in any annulus is at least 200 psig greater than the pressure measured during the previous diagnostic test... A diagnostic test is required to begin as soon as practical (see § 250.526). (f) You conduct workover operations on the well... You must conduct a new diagnostic and submit a departure request if any pressure remains after the workover (see § 250.532).
§ 250.529 What are the MMS requirements for monitoring casing pressure in floating production or subsea developments?	§ 250.529 What are the MMS requirements for monitoring casing pressure insubsea wells and hybrid wells?	General Comment: Both industry and MMS have little experience with SCP in hybrid wells located on floating systems. Therefore, highly prescriptive regulations are not advisable, may limit technology and operational advances. We strongly advise a more performance based regulation in this area. We believe that operators should submit their plans for monitoring pressures and propose acceptable levels of SCP for

Proposed Rule	Propose Language	Rational for Change
		<p>their particular system in the Deepwater Operations Plan. The hazard to personnel, the environment, the platform or the producing formation should be considered in determining if a pressure on an annulus is acceptable and comparable with other wellbore configurations.</p> <p>However, if MMS continues with a highly prescriptive approach, we have provided detailed comments on that approach.</p>

<p>(a) The MMS policy for wells that are located on floating platforms or vessels (Tension Leg Platforms's, Spars, etc.) is as follows:</p> <p>(1) You must monitor pressures in the production riser on a continuous basis. If you encounter pressure on the production riser, you must report it immediately to MMS. As part of this notification, you must describe how the pressure will be diagnosed to confirm its magnitude and source.</p> <p>(2) You must automate pressure monitoring in the tubing/riser annulus above the mud-line isolation, and establish high- and low-pressure set points to provide an indication of either a tubing or riser leak.</p> <p>(3) MMS will not grant any departures in the "life-of-completion" category for wells where all annuli cannot be monitored for pressure.</p> <p>(4) You must meet the requirements of the following table:</p> <p>If... Then...</p>	<p>(a) The MMS policy for hybrid wells that are located on floating platforms or vessels (Tension Leg Platforms's, Spars, etc.) is as follows:</p> <p>(1) You must monitor pressures in the production riser on a continuous basis, unless otherwise approved in your Deepwater Operations Plan. If you encounter pressure on the production riser that is not self imposed, you must report it immediately to the District Supervisor. As part of this notification, you must describe how the pressure will be diagnosed to confirm its magnitude and source.</p> <p>(2) You must automate pressure monitoring in the tubing/riser annulus above the mud-line isolation (if installed), and establish high- and low-pressure set points to provide an indication of either a tubing or riser leak.</p> <p>(3) You may not place any wells in "life-of-completion" status where all riser annuli cannot be monitored for pressure.</p> <p>(4) You must meet the requirements of the following table:</p> <p>If... Then...</p> <p>(i) You have a dual-bore production riser ... MMS will allow you to maintain SCP on the inner bore only under the following circumstances:</p>	<p>1. Clarifies that this section applies to hybrid wells, not subsea wells.</p> <p>2. An operator may propose an alternate monitoring program in their approved Deepwater Operations Plan.</p> <p>3. In most cases, the inner bore of a dual bore annulus will be filled with nitrogen; therefore, pressure will be self imposed, and the outer bore will be filled with a liquid or a gel. In some cases, operators may also gas lift down the inner bore in which case pressure would also be self-imposed.</p> <p>4. Clarifies whom to notify.</p> <p>5. Clarifies that this applies to the riser annuli.</p> <p>6. We believe that the life of completion status is appropriate under the conditions described. In some cases the source of pressure may not be formation pressure, but could be such things as a leaking gas lift valve.</p> <p>7. In many cases, the outer riser string has a lower MIYP than the inner casing. Limiting the amount of pressure on the inner casing ensures that should pressure from the inner casing be imposed on the outer casing, the MIYP of the outer casing will not be exceeded.</p> <p>8. We see no technology bases rational for requiring that no pressure be allowed on the outer bore of a dual bore casing. The casing has been designed to hold pressure.</p> <p>9. Allowing 500 psig of pressure on either a single bore or the outer bore of a dual bore riser is reasonable considering that these risers are designed to hold pressure. Allowing this small amount of pressure will allow production to continue while the operator is preparing plans to workover the well and eliminate the pressure.</p> <p>10. The proposed rule addresses SCP, but not thermally induced pressure. In wells completed with a subsea wellhead, the heat effects generated by production upon trapped fluid in casing annuli are quite substantial. This effect is considered in the design of the tubulars. The thermally induced pressures in some cases may exceed the pressure limits (% of MIYP) proposed by MMS in the regulation for SCP. A diagnostic test to confirm if the pressure is thermally induced versus SCP</p>
--	--	---

<p>(ii) You have a single-bore production riser and detect pressure in the tubing/riser annulus, and the diagnostic test confirms that the pressure is SCP... You must either kill the well or set a plug to eliminate the pressure in the tubing/riser annulus.</p>	<p>Supervisor may allow production from the well to continue or may require the well to be shut in, killed or a plug set to eliminate the pressure on the inner bore.</p> <p>(D) You must conduct a diagnostic test at least every 6 months. You must conduct the test as soon as practical if the pressure increases more than 200 psig above the currently approved level.</p> <p>(E) You must cease production if the well experiences formation-related pressure on the outer riser annulus or if the pressure on the inner bore exceeds 50% of the MIYP of the outer bore.</p> <p>(F) SCP on the outer bore of a dual bore riser system will be treated the same as a single bore riser.</p> <p>needs to be carefully designed. Heat from the trapped fluids will transfer to the producing formation and elevate the temperature in the immediate vicinity of the wellbore. Therefore, if the well is shut-in, the pressure in the annulus may not fall to zero for a long time since the elevated formation temperature will continue to heat the annular fluid. Each time the well is shut in, the temperature will rise with a stair-step effect until a steady state temperature is reached. Thermally induced pressure may be more readily confirmed by reducing the production rate and confirming that the annular pressure also decreases.</p>
--	--

<p>(b) For subsea wells (wet tree), you must meet the requirements of the following table:</p> <p>If... Then...</p>	<p>(b) For subsea wells , you must meet the requirements of the following table:</p> <p>If... Then...</p> <p>(1) You have a subsea well where only the production annulus can be monitored...</p> <p>(i) You must conduct diagnostics as indicated in § 250.526, except that the results for adjacent annuli will be limited to monitoring tubing pressure response if the wellhead was installed before January 1, 2005.</p> <p>(ii) You must obtain permission from MMS for maintaining any SCP.</p> <p>(iii) You must monitor the well for casing pressure continuously.</p> <p>(2) You install a subsea tree after January 1, 2005... According to 30 CFR 250.517(c), you must provide a method for monitoring all casing annuli for SCP.</p>	<ol style="list-style-type: none"> 1. The imposition of “fixed platform well” regulatory requirements for “subsea wells” trees used in subsea barriers and the basic assumptions that are used in building the subsea tree well system. The past historical experience of the use of subsea wells in the GOM reflects a prudent and successful development tool that adequately addresses the dynamic pressure environment that both the structural and pressure containment elements of a typical sub sea system utilize. The DWOP should be utilized to address both advancements in hardware capability and the operator processes developed to ensure safe prudent operations in managing subsea wells. We know of no single instance of a casing pressure in sub sea wells that have cause any blowouts or uncontrolled well flows to the surface. In addition, the potential risk to personnel and platforms in the highly unlikely event that pressure on the casing led to a an uncontrolled well flow is vastly different for subsea wells than for surface tree wells. This difference in risk should also be taken into consideration in lieu of treating subsea wells similar to fixed platform wells. 2. See comments above for permission versus approval. 3. It may not be possible in all cases to monitor the annulus continuously. Even when equipment is installed for continuous monitoring, it may fail, tubing become plugged, etc. 4. Please see our detailed comments on monitoring all annuli when subsea wellheads have been utilized. Please note that the subsea wellhead is installed when the well is drilled. The tree may not be installed for several years following the drilling of the well. Many of wells for which the subsea tree will be installed after January 1, 2005 will be drilled in next couple of years. Subsea wellheads are not currently available that will allow all annuli to be monitored. Therefore, when the subsea tree is set after January 1, 2005, these wells will be out of compliance. The timeframe in the proposed regulation is unrealistic. 5. See discussion above on thermally induced pressures.
---	---	---

provide a report on the status of all SCP to MMS and the new owner/operator.	
§ 250.531 What is the MMS policy for SCP in non-producing wells?	<p>(a) No casing pressure of any kind is permitted on a temporarily abandoned well. This does not include newly drilled wells that have been temporarily plugged pending the installation of production facilities, pipelines, etc. For these wells, if you detect SCP, you must contact MMS and submit a plan of action.</p> <p>(a) Casing pressure on temporarily abandoned wells is treated the same as on producing wells. This does not include newly drilled wells that have been temporarily plugged pending the installation of production facilities, pipelines, etc. For these wells, if you detect SCP, you must contact MMS and submit a plan of action.</p> <p>1. Industry understands and accepts that the SCP regulations are not developed to permit the indefinite postponement of needed repairs to any wells. However, wells with minimal SCP do not present a greater risk than producing wells with minimal SCP. An assessment of risk using sound engineering practices should dictate whether any well should be repaired or P&A'd, opposed to a blanket policy. Unless the wellbore conditions present a greater hazard to personnel, the environment, the platform or to a producing formation that a similar wellbore that is currently producing, then there is no reason to require that the well be repaired or P&A'd.</p>

<p>(b) For non-producing wells that are neither temporarily abandoned nor continuously injecting, you must meet the requirements of the following table:</p> <p>If...</p> <p>Then...</p>	<p>(b) For non-producing wells that are neither temporarily abandoned nor continuously injecting, you must meet the requirements of the following table:</p> <p>If...</p> <p>Then...</p> <p>(1) Your well fails to bleed to zero... You must submit plans for the repair of the SCP condition within 30 days.</p> <p>(2) You determine the well will not be returned to production... You must submit plans for the repair of the SCP condition within 30 days.</p> <p>(3) You have not used the well for continuous production or injection for 1 year... Before the end of the year of non-production/injection, you must have assessed the well and presented a plan to MMS. The plan must include both diagnostic test results and a plan of action. The plan must describe when and how:</p> <ul style="list-style-type: none"> (i) the well will be returned to production; or (ii) the SCP will be eliminated. 	<p>The MMS notes in the preamble that they have “sought to identify and eliminate SCP in only those cases that represent a hazard.” In keeping with that intent, it is industry’s contention that those non-producing wells that fall into the “Fixed Term Status” category would be consistent with this statement and should require this type of attention and action. Many non-producing wells are future sidetrack candidates and do not warrant the loss of natural resources by premature abandonment that would occur with the proposed one-year period mandated by the policy. Data from one major GOM operator indicates that approximately 45% of wells drilled over the last two years were sidetracks. It is clear that as reserve bases continue to shrink, industry needs economical options such as sidetracks to be able to continue to produce on the OCS.</p> <p>The cost of this proposed rule is significant as written. These rules require plans for repair of ALL non-producing wells with a SCP condition within very near term time frames as proposed in paragraphs (1) and (2) of this section. Using the cost range provided by MMS for well repair and workovers, the accelerated repair or abandonment requirements for these wells will cost industry between \$540,000,000 and \$2,700,000,000 in the near term, if the proposed regulation is adopted. Due to this significant economic impact, industry strongly recommends that decision be made based on risk using sound engineering practices, not just a blanket policy.</p> <p>§ 250.532 What if I conduct a workover on a well with SCP?</p> <p>If you perform a workover requiring the submission of Sundry Notices and Report on Wells (form MMS-124) according to § 250.613, it invalidates any existing SCP departure for that well. When you conduct a workover on a well with SCP, you must make all repairs feasible to eliminate SCP consistent with the use of the equipment used for the workover. You must then notify MMS of the results using form MMS-124. A new diagnostic test is required on any remaining SCP.</p> <p>We recommend changing the definition here to clarify and simplify which types of workovers are covered by this rules. In most cases, workovers, which are performed with the tree in place, will not have any effect on SCP.</p> <p>SCP should be addressed in the Sundry Notice for the proposed workover. Even though equipment might be on the platform that can eliminate the SCP, the operator should provide an assessment of the SCP and explain why the pressure will not be eliminated during the workover.</p>
--	---	---

OOC-MMS Meeting on SCP



INTRODUCTION

Thank MMS for Opportunity to discuss SCP at a high level.

Confirm that Industry views the proposed rule making as a significant understanding

Confirm that the issue is critical and should be addressed.

Review and discuss potential solutions to identified problems.

OOC-MMS Meeting on SCP

PARTICIPANTS



Industry Representatives:

- Steve Brooks OOC Chairman Technical S/C
- Ross Frazer IPAA Representative
- Chris Nelson OOC Deepwater S/C
- Wanda Parker OOC Technical S/C
- Andy Radford API Technical Team
- Allen Verret DeepStar CTR 5100



OOC-MMS Meeting on SCP

AGENDA

- Historical Overview of Issue—Industry
- Comments & Action on Past NTL's
- Past Actions Taken & Results
- Recent Review and Comments Developed
- Proposed Surface Tree Solutions
- Discussions on Sub Sea Wellheads & Sub Sea Systems

OOC-MMS Meeting on SCP



OBJECTIVE OF MEETING

- Review Issues associated with Proposed Rulemaking at high level
- Identify its significance to operators and explain impact
- Offer alternative potential solutions
- Discuss near term and long term efforts on topic

OOC-MMS Meeting on SCP



DESIRED OUTCOME

MMS better understand OOC position regarding SCP proposed regulations.

MMS will consider implementation of OOC recommendations to be included in the formal comments to proposed rule.

SCP Regulation-- History

History

- Numerous policies and LTLs have been issued since 1977 with various technical and reporting requirements
- OOC has worked with MMS since 1988
- Over 8000 wells (11,000 casing strings) in the GOM have SCP



SCP Regulation-- History



Reported Uncontrolled Well flow—MMS Records

- 2 wells—underground blowouts (1987, 1992)
- 1 well—communication with another well—source was shallow water sand (1987)
- 1 well—flow between prod and inter csg (1976)

No injuries have occurred

Minor pollution from one incident

No reported uncontrolled well flow from subsea wells or hybrid wells

SCP Regulation-- History



When is pressure on the casing an unacceptable risk?

- OOC report from 1989

Did not answer the question—set criteria for wells which do not pose a hazard, took no position on wells that did not meet criteria

1000 psi based on imposed gas lift pressure, represents 14-28% of MIYP of common casing designs
20% of MIYP or 1000 psi represents 50% or less of MIYP of the next outer string

SCP Regulation-- History



When is pressure on the casing an unacceptable risk? Cont'd

— LSU Study, July 31, 2001

Technical criteria based on the ratio of casing pressure to its strength and the ability to bleed to zero pressure are arbitrary to some degree

SCP Regulation-- History



	Conn. OES Order 6, Aug 28, 1969	1988 Rulemaking	LTL 1991	LTL 1994
Wellhead Equipment	Connections to permit fluid to be pumped between any 2 strings of csg	Wellhead equipped--all annuli monitored for SCP	Wellhead equipped so that all annuli can be monitored for SCP	Wellhead equipped so that all annuli can be monitored for SCP
Monitoring	None	None	Monthly	Not specified
Reporting	None	Immediate notification to Dist. Supervisor	Immediate notification to Dist. Supervisor	All csg pressure (except drive or structural) immediately reported to Dist Supervisor
Testing	Wells showing SCP on the casinghead or leaking gas or oil between the prod csg and next string: well killed and pump pressure applied. If casinghead pressure reflects pump pressure the casing is condemned.	None	< 20% Yield and Bleed to 0 --Not submitted to MMS --Rerun ---+200 psi on inter or prod ---+100 psi on cond or surf >20% Yield/ Do Not Bleed to 0 --Submit to MMS for approval	< 20% Yield and Bleed to 0 --+200 psi on inter or prod --+100 psi on cond or surf >20% Yield or Do Not Bleed to 0 --Submit to MMS Region office for approval
Subsea Wells	2/24/2002			Remote --same as above Manual—2 year interval 5

SCP Regulation— Proposed Rule



Fixed Platform Wells, Cont'd

— Process

- Very burdensome on both MMS and Industry
- Technical basis for monitoring and diagnostic test requirements is unclear
- Timeframe for submitting the diagnostic tests is unrealistic

SCP Regulation— Proposed Rule



Fixed Platform Wells

- Technical Criteria**

- Arbitrary basis—assumes all pressure is a hazard, no distinction between pressure sources
- No distinction between pressure containing casing and structural casing
- Testing protocols are extremely prescriptive
- Imposes a different criteria for non active wells versus active wells that doesn't appear to be based on risk

SCP Regulation— Proposed Rule



Subsea Wellheads

- Confusion between wellhead and tree
- Potential hazards are not the same as for platform wells
- Imposition of dry wellhead regulations on wet wellheads does not have a sound technical basis
- Impacts the design of the subsea system, not just the wellhead
- Subsea systems are not of consistent design and application

SCP Regulation— Proposed Rule



Floating System (Hybrid Wells)

- Subsea wellhead, dry tree
- Little experience with this type well
- Systems are not of a consistent design
- No technical or risk basis for proposed limits
- Limits the development of hardware and operating practices

SCP Regulation— OOC Proposal



When does pressure on the casing pose an unacceptable risk?

- 3 Prong Approach
 - Third party study of casing pressure and risk
 - Develop an API RP on casing pressure
 - Re-evaluate risk study used as a basis for API Spec 17D subsea wellhead design

SCP Regulation— OOC Proposal



When does pressure on the casing pose an unacceptable risk? Cont'd

- Develop a risk based recommended practice based on the findings from the 3rd party study
- Risk to personnel, equipment, environment

Casing design

Pressure source

Monitoring

Testing protocols

Diagnostics

Remediation

Documentation

SCP Regulation— OOC Proposal



When does pressure on the casing pose an unacceptable risk? Cont'd

- Address all types of wells and pressures appropriately

Fixed Platform

Subsea

Hybrid

SCP and Unsustained casing pressure

SCP Regulation— OOC Proposal



When does pressure on the casing pose an unacceptable risk? Cont'd

- Monitoring Requirements for Subsea Wellheads

Re-evaluate risk associated with wellhead design in
API Spec 17D

SCP Regulation— OOC Proposal



Reporting procedure

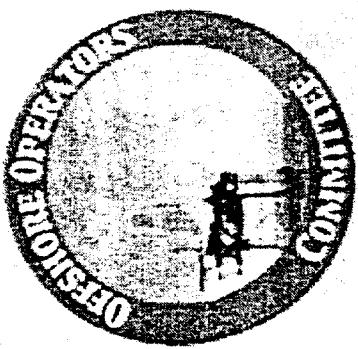
- Work with MMS to establish appropriate reporting procedures that are not overly burdensome on MMS or Industry



SCP Regulation— OOC Proposal

- MMS either withdraw proposed rulemaking or hold it in abeyance until RP is developed
- Existing LTL (1994) remain in effect for platform wells until RP is completed and adopted into regulation
- Subsea wells and hybrid wells continue to be handled on a case-by-case through the DWOP process

Subsea System Issues



Subsea System Components Impacted

- Subsea Wellhead
- Subsea Tree
- Umbilicals / Subsea Manifolds
- Surface Control Systems

Subsea System Issues



Subsea Wellhead (SSWH)

- First Component Impacted
- Currently a completely pressure sealed system
- Significant design/manufacturing changes required to allow access to all annuli outside of the production annulus
- All subsea wells would have to use this type of SSWH

Subsea System Issues



Monitoring/Venting System Weaknesses

- Monitoring system used could introduce leak paths which could expose system (other annuli) to high pressure
- Use of valves and their inherent reliability issues
- Plugging of access ports with debris from annuli including mud solids and formation solids
- Hydrate formation (Water depth /temperature)
- Could lead to wells being shut in due to the monitoring system failure
- Proposed Diagnostic Approach would have to be modified to account for water depth and tie-back length

SS-15® BIGBORE SUBSEA WELLHEAD SYSTEM

Drill Quip's Big Bore Subsea Wellhead System allows casing string changes and seal assembly (typically 18" to 16") to pass through the 18 $\frac{3}{4}$ " wellhead with the BOP stack and riser in place. This accommodates drilling and running large bore diameter casing string through pressurized water stands with complete BOP control and with all returns back to surface. The illustration to the right shows a 36" x 26" x 22" x 18" x 16" x 13 $\frac{5}{8}$ " x 9 $\frac{1}{8}$ " casing program.

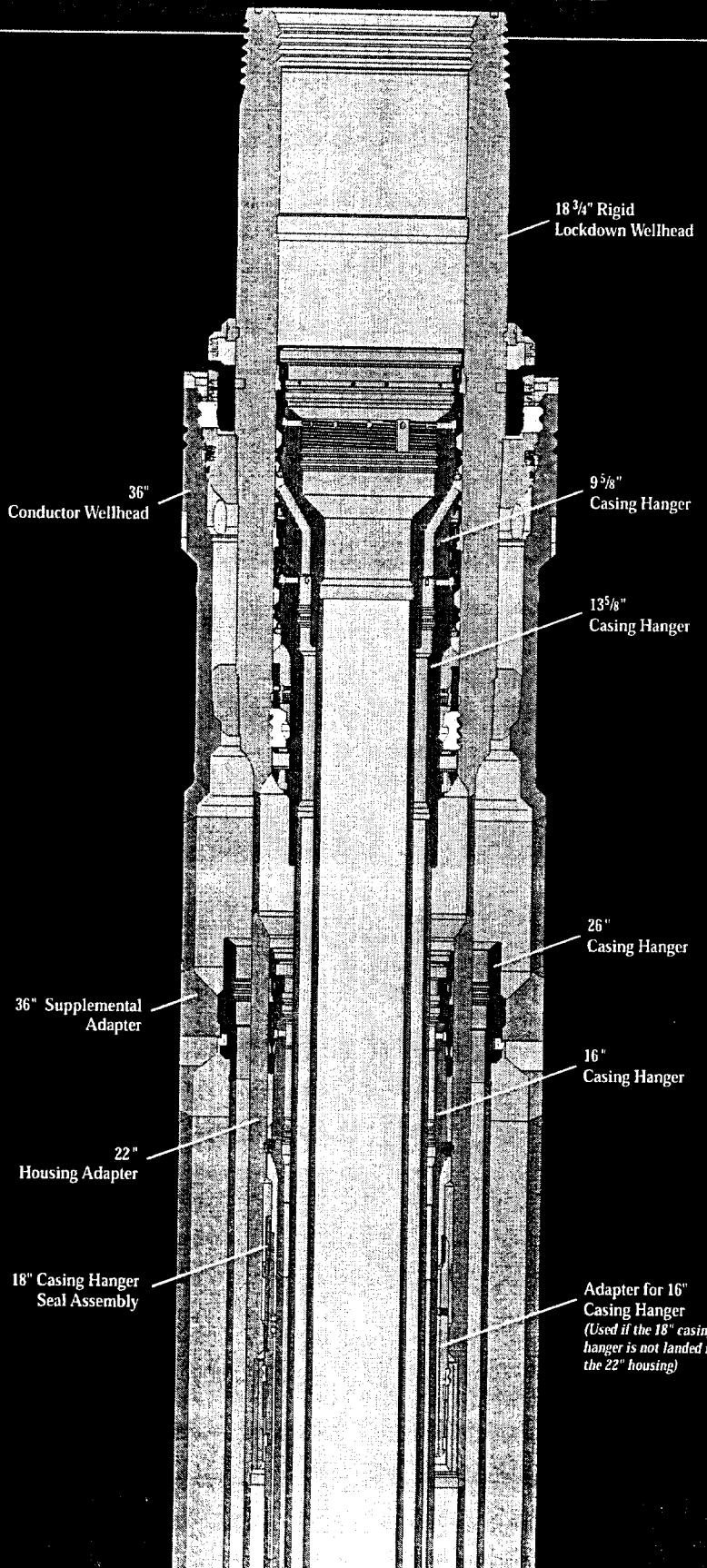
Optional 36" supplemental adapter can be run in order to accommodate a secondary conductor string.

18 $\frac{3}{4}$ " wellhead housing designed for 15,000 psi and 6.2 million pounds end-load capacity.

- Special 18 $\frac{3}{4}$ " wellhead allows 18" casing and hanger to pass through it
- 22" adapter supplies landing shoulder and seal area for 18" and 16" supplemental casing hanger systems
- All casing hangers and seal assemblies are run, set and tested on drill pipe in a single trip
- Incorporates all of the other features of the field proven SS-15 Wellhead System

DRILL QUIP®

HOUSTON ABERDEEN SINGAPORE
(713) 939-7711 (01224) 727000 (65) 861-0600

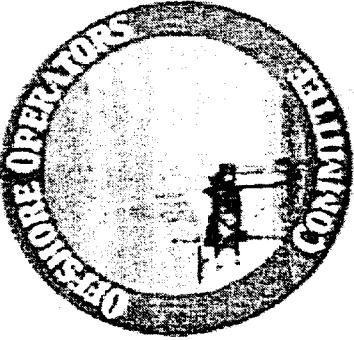


SS-15 BIG BORE WELLHEAD SYSTEM

APPLICATIONS

- **Shallow Water Flow Environment**
- **Deepwater / Deep TVD Wells**
- **Pressurized Sands in Top Hole Sections**

Subsea System Issues



A Safer Approach

- Require the well design to withstand potential sustained casing pressures from:

Thermally Induced Sources

Exposed Formations (Water/Hydrocarbon Sands)

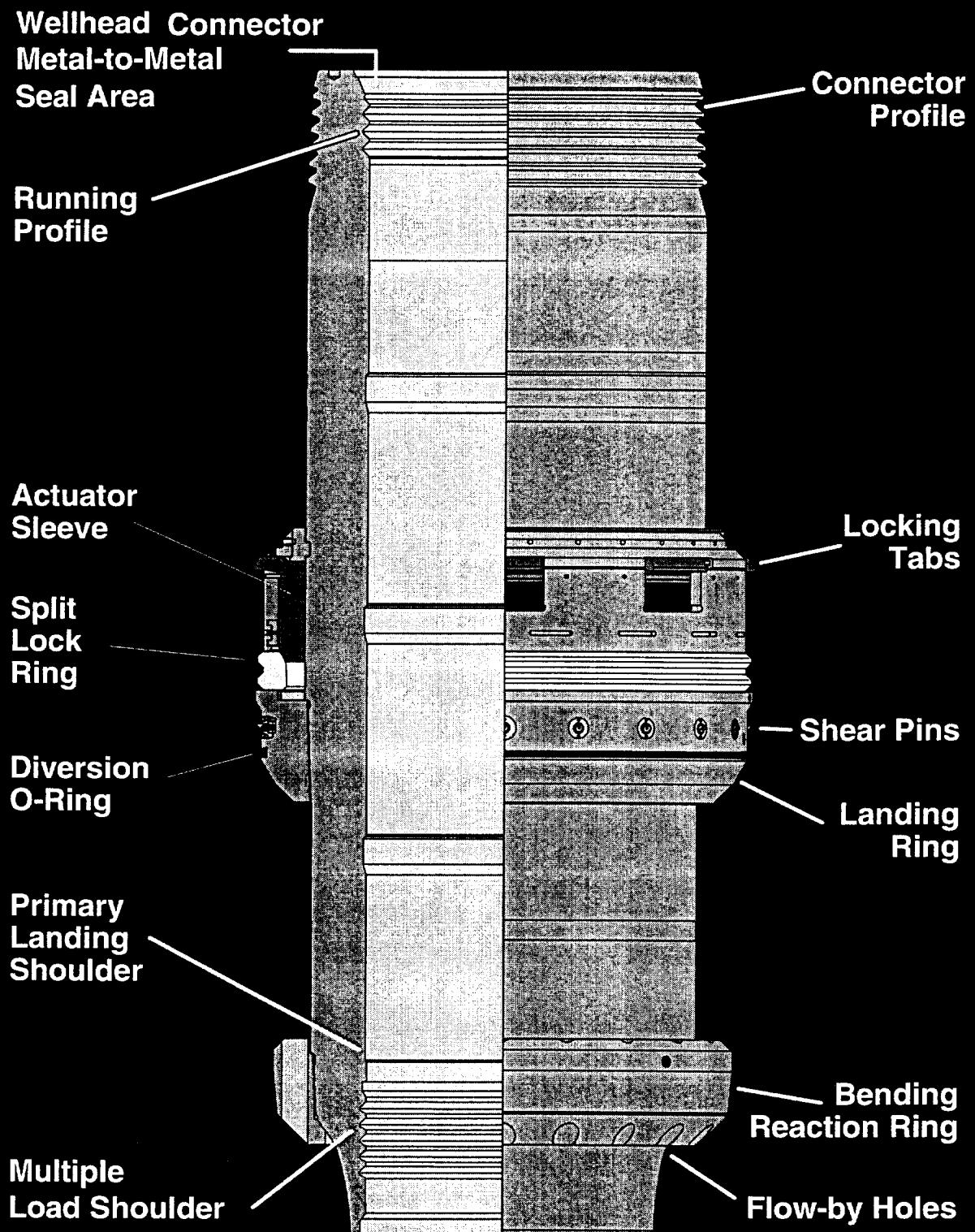
Self Induced Pressure

- Well Design Components include:
 - Casing Design and Cementing Program
- Be prepared for SCP issues when abandoning the well

SS-15 BIG BORE WELLHEAD SYSTEM

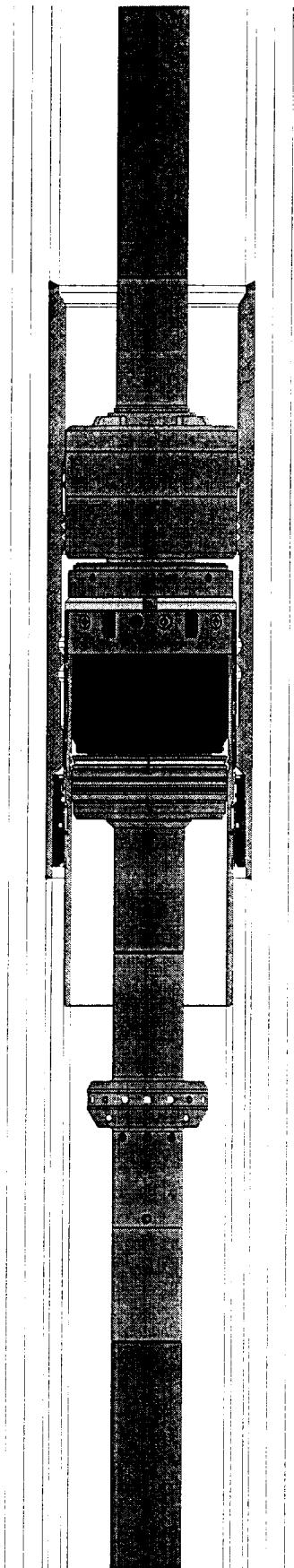
FEATURES / BENEFITS

- Allows additional casing string (18") to be run after installation of standard 21" riser and 13-3/8" EOP Seal
- Supplemental Casing Hangers (18" and 16") are integrated sealed in supplemental adapter assembly to support load from eccentric load plates.
- New 13-3/8" (13-5/8") Casing Hanger for improved seal coverage during load changes for high integrity service.
- A full range of wellhead components including Casing Hangers, Riser, Flowline, and Seal Assembly are available for the SS-15 Big Bore Wellhead System.



18-3/4" BigBore Wellhead Housing

Subsea Wellhead Systems Type SS-15 *



**Run 18" Supplemental Casing Hanger and Seal Assembly
with Casing Hanger Seal Assembly Running Tool**

DRIL-
QUIP®

SS-15 Big Bore Subsea Wellhead System

TP 31505-20

* A Trademark and Service Mark of DRIL-QUIP, Inc. © Copyright 2000 DRIL-QUIP, Inc.

**Anti-Rotation
Slot**

**Lock Ring
Grooves**

**Load
Shoulder**

**Running
Tool
Seal Area**

**Activator
Ring**

**Retainer
Ring**

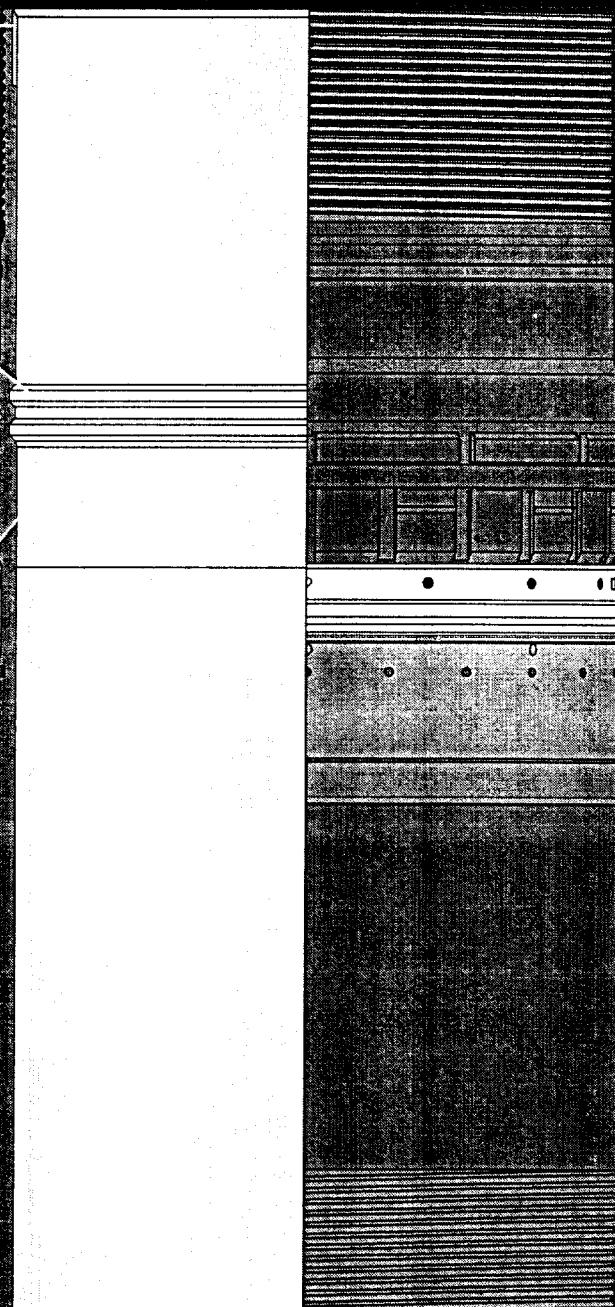
**Left-Hand
Threads**

**Seal
Assembly
Sealing
Area**

**Split
Load
Ring**

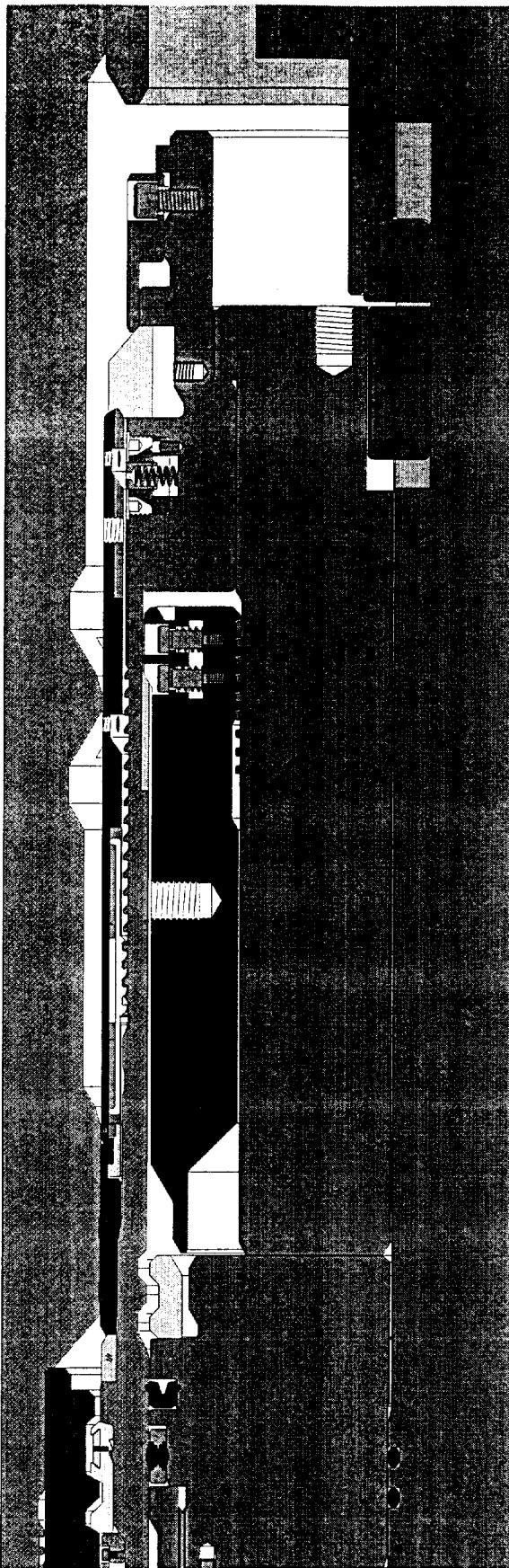
**Grooved
Shear
Pin**

**Casing
Threads**



18" Casing Hanger
SS-15 BigBore Subsea Wellhead System

**DRILL
QUIP**



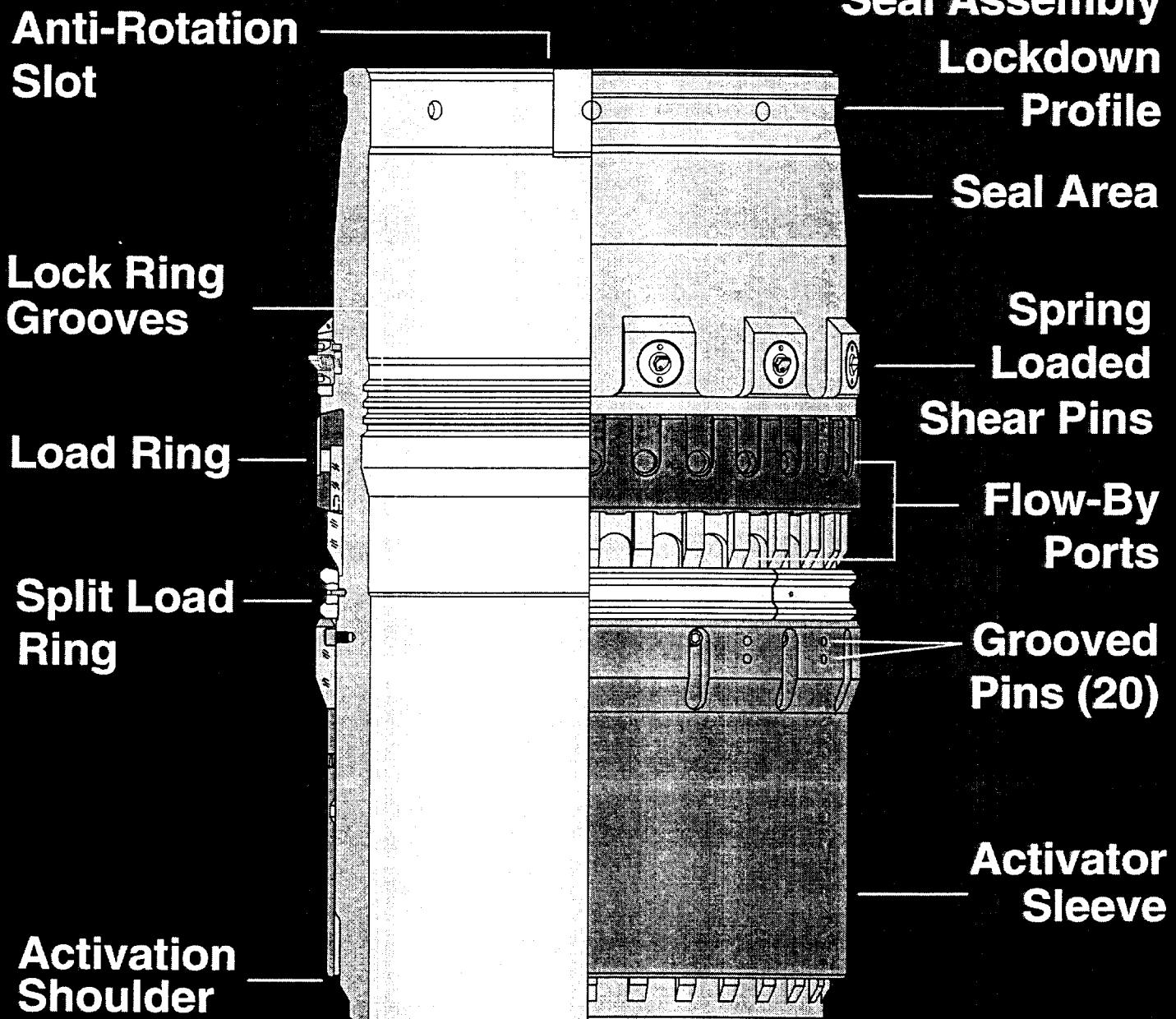
**18" Seal Assembly Weight-Set, Tested,
and Locked to the 18" Supplemental Hanger**

SS-15 Big Bore Subsea Wellhead System

TP 31505-23

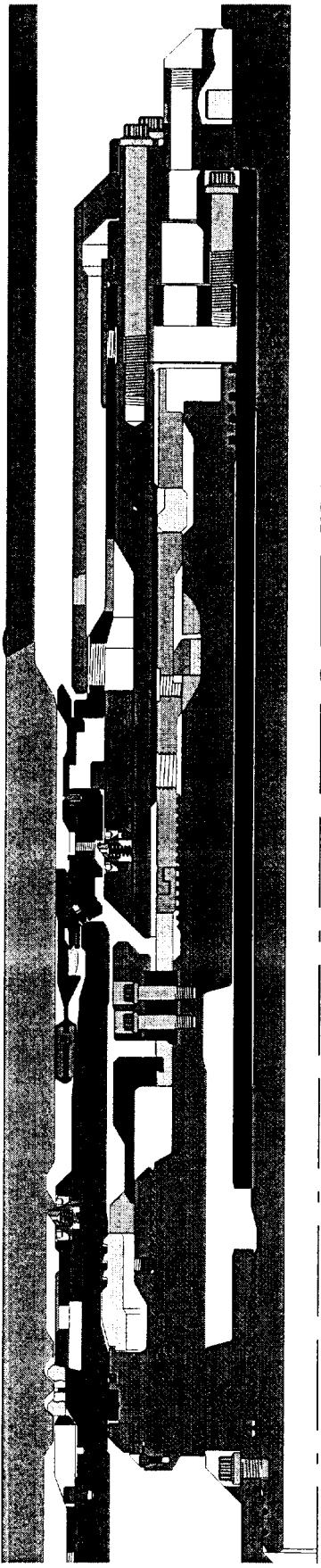
* A Trademark and Service Mark of DRIL-QUIP, Inc. Copyright 2000 DRIL-QUIP, Inc.

DRIL-
QUIP®



16" Casing Hanger
SS-15 Big Bore Subsea Wellhead System

**DRIL
QUIP**



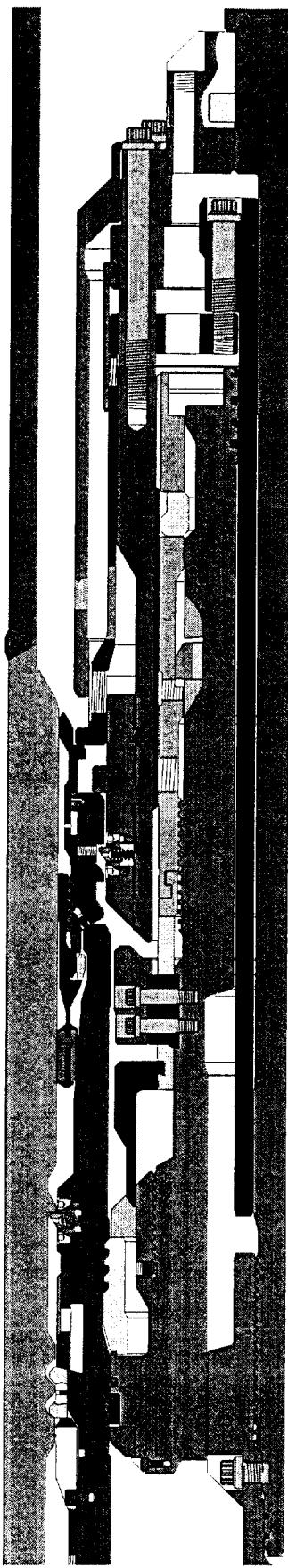
**16" Casing Hanger and Seal Assembly Running Tool,
Seal Assembly Landed on Hanger**

SS-15 Big Bore Subsea Wellhead System

TP 31505-30

* A Trademark and Service Mark of DRIL-QUIP, Inc. Copyright 2000 DRIL-QUIP, Inc.

**DRIL-
QUIP®**



**Casing Hanger and Seal Assembly Running Tool,
Seal Assembly Tested and Locked Down**

SS-15 Big Bore Subsea Wellhead System

TP 31505-31

* A Trademark and Service Mark of DRIL-QUIP, Inc. Copyright 2000 DRIL-QUIP, Inc.

DRIL
QUIP

**Seal
Assembly
Locking
Groove**

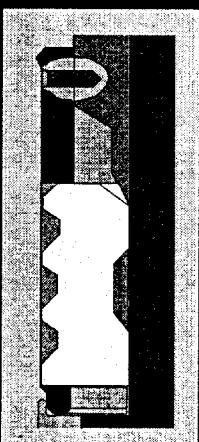
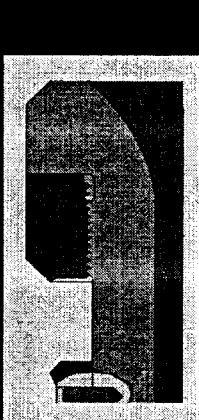
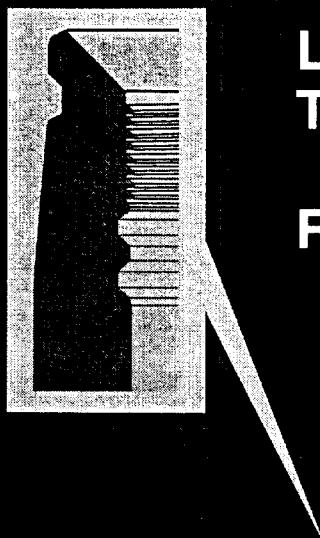
**Metal
Sealing
Surface**

**Primary
Landing
Shoulder**

**Actuating
Sleeve
Gap**

**Actuator
Sleeve**

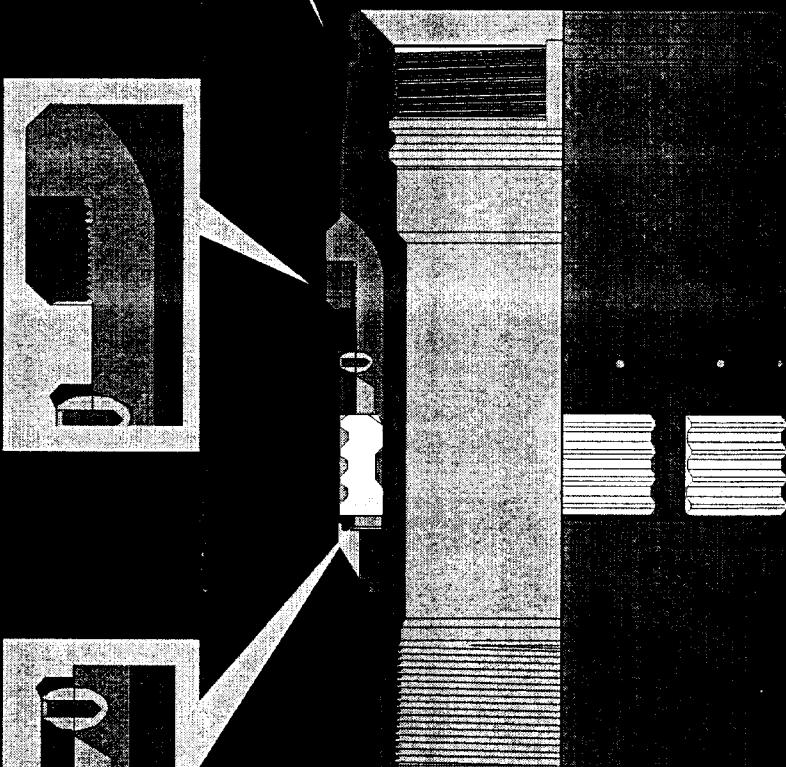
**Split Load
Ring**



**Landing Seat
Tieback Threads**

Running Profile

18.615"
MAX.
O.D.

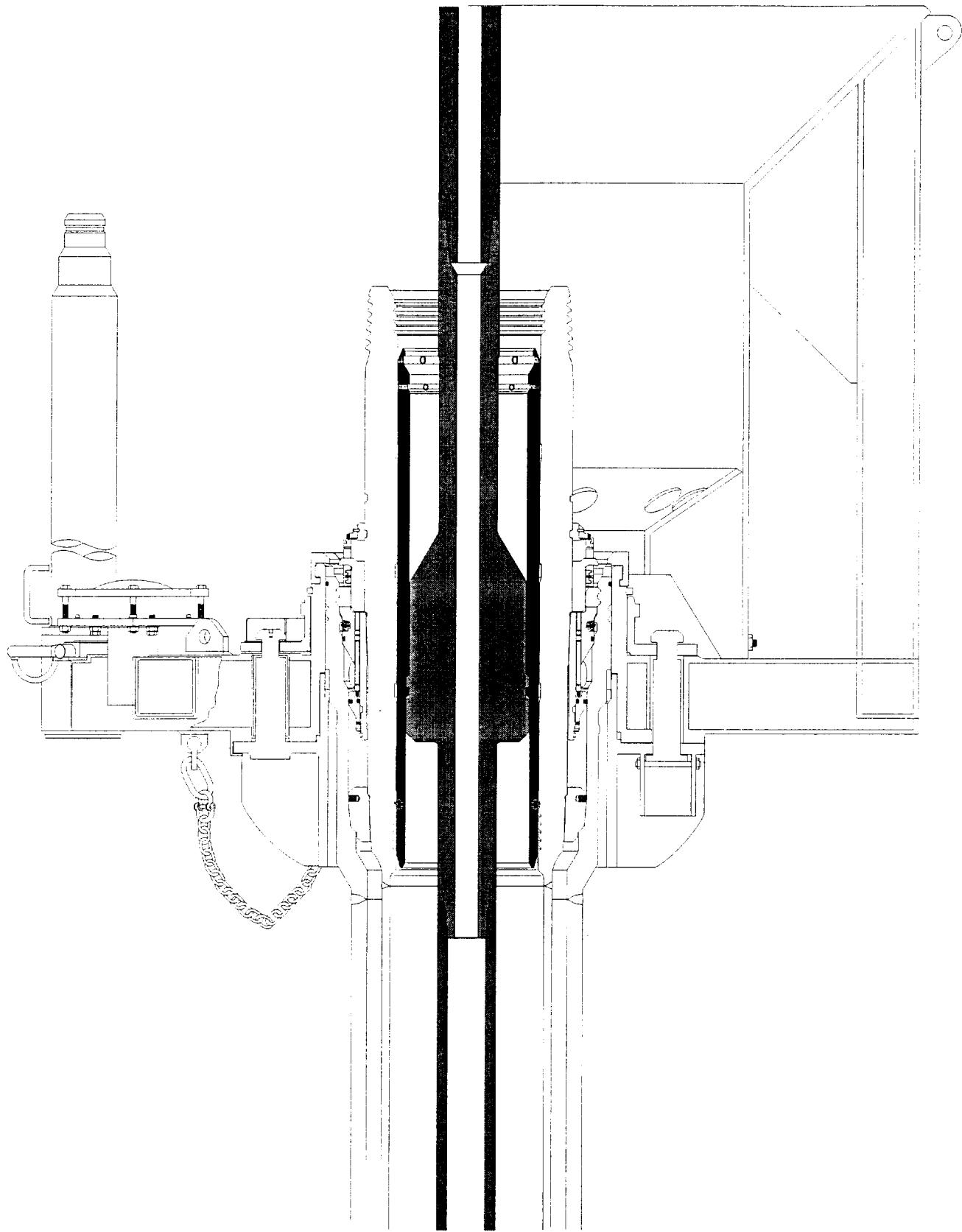


30.60"
O.A.L.

12.375"
MIN.
I.D.

13-3/8" Casting Hanger
SS-15 BigBore Subsea Wellhead System

DRI
QUIP



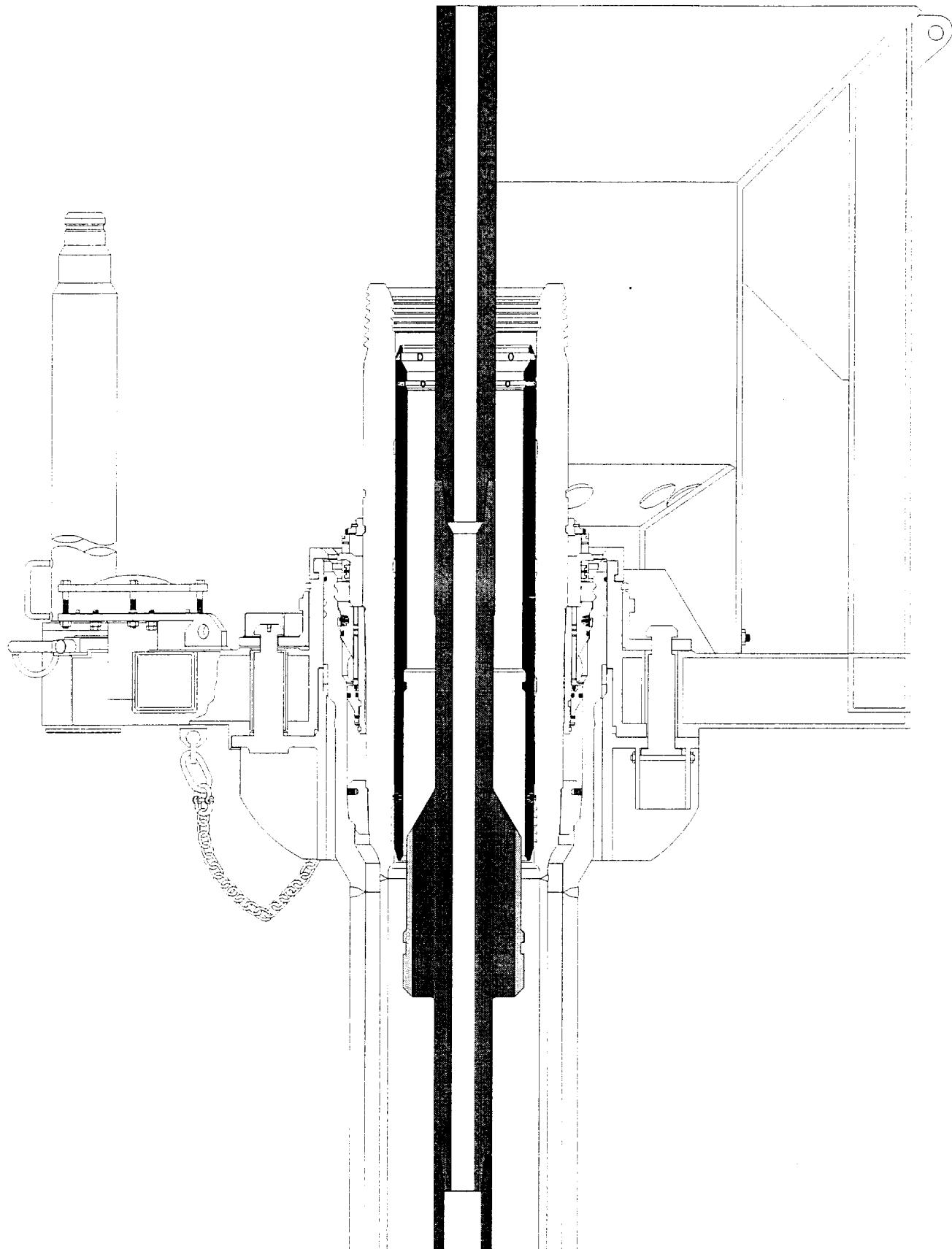
**Run 18"/16" Wear Sleeve on
Bit Sub**

SS-15 Big Bore Subsea Wellhead System

TP 31505-15

* A Trademark and Service Mark of DRIL-QUIP, Inc. © Copyright 2000 DRIL-QUIP, Inc.

**DRIL
QUIP**



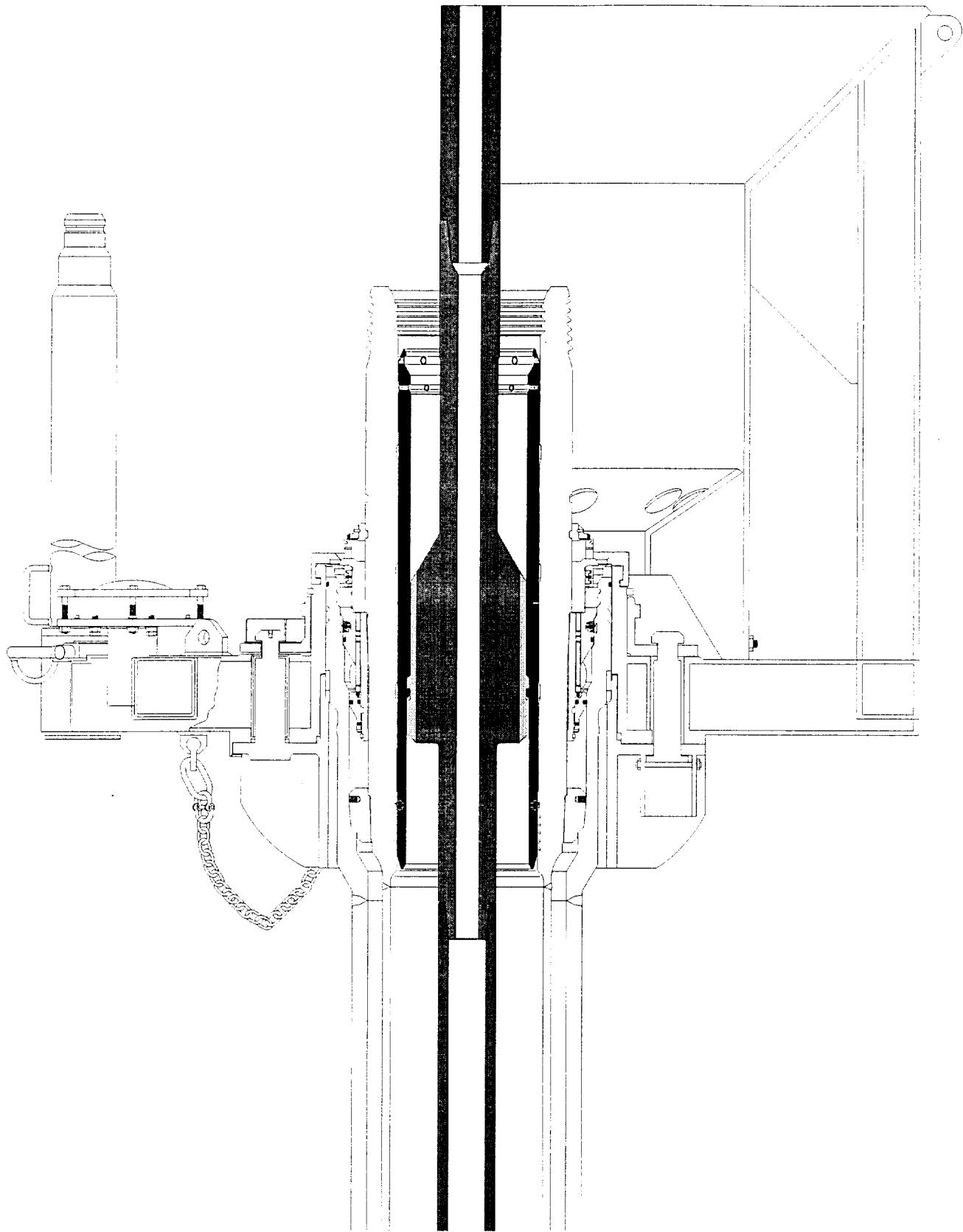
Bit Sub in Drill Ahead Mode

SS-15 Big Bore Subsea Wellhead System

TP 31505-16

* A Trademark and Service Mark of DRIL-QUIP, Inc. © Copyright 2000 DRIL-QUIP, Inc.

DRIL
QUIP



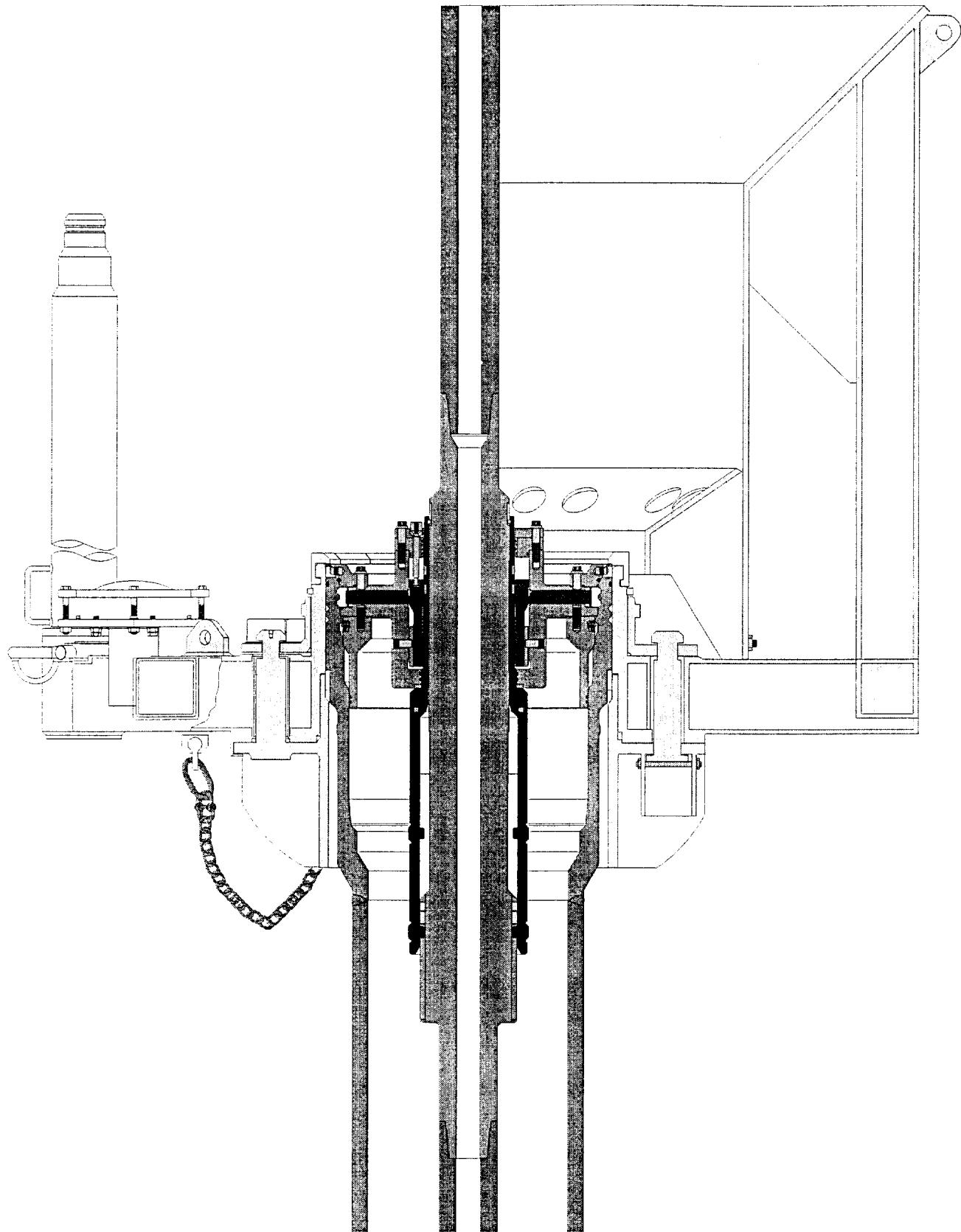
**Retrieve the Wear Sleeve with
the Bit Sub**

SS-15 Big Bore Subsea Wellhead System

TP 31505-19

**DRIL-
QUIP®**

* A Trademark and Service Mark of DRIL-QUIP, Inc. © Copyright 2000 DRIL-QUIP, Inc.



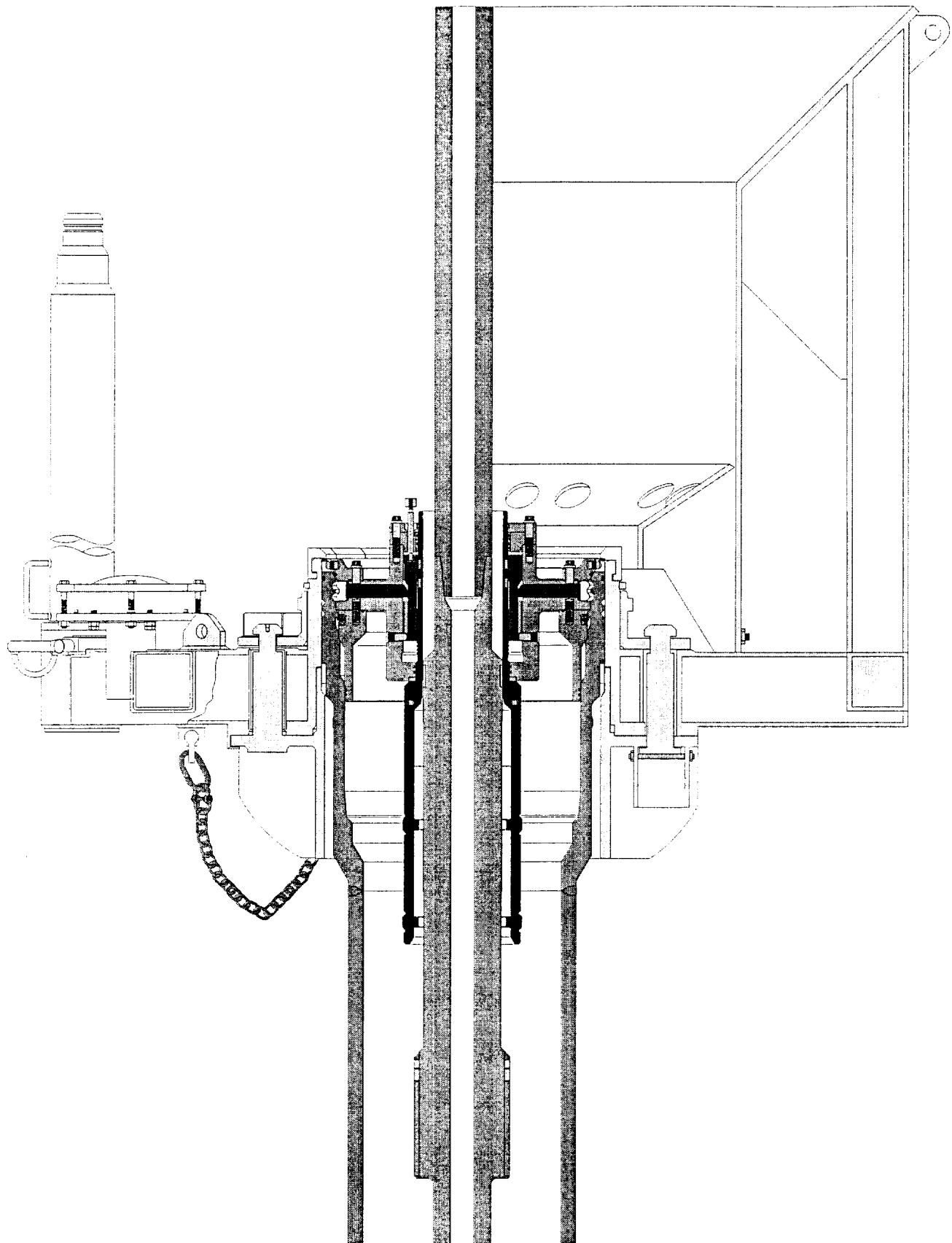
**Run Permanent Guide Base and 36" Rigid
Lockdown Wellhead on CADA Tool**

DRIL
QUIP

SS-15 Big Bore Subsea Wellhead System

TP 31505-02

* A Trademark and Service Mark of DRIL-QUIP, Inc. Copyright 2000 DRIL-QUIP, Inc.



Run CADA Tool in Drill Ahead Mode

SS-15 Big Bore Subsea Wellhead System

TP 31505-03

* A Trademark and Service Mark of DRIL-QUIP, Inc. © Copyright 2000 DRIL-QUIP, Inc.

DRIL-
QUIP®

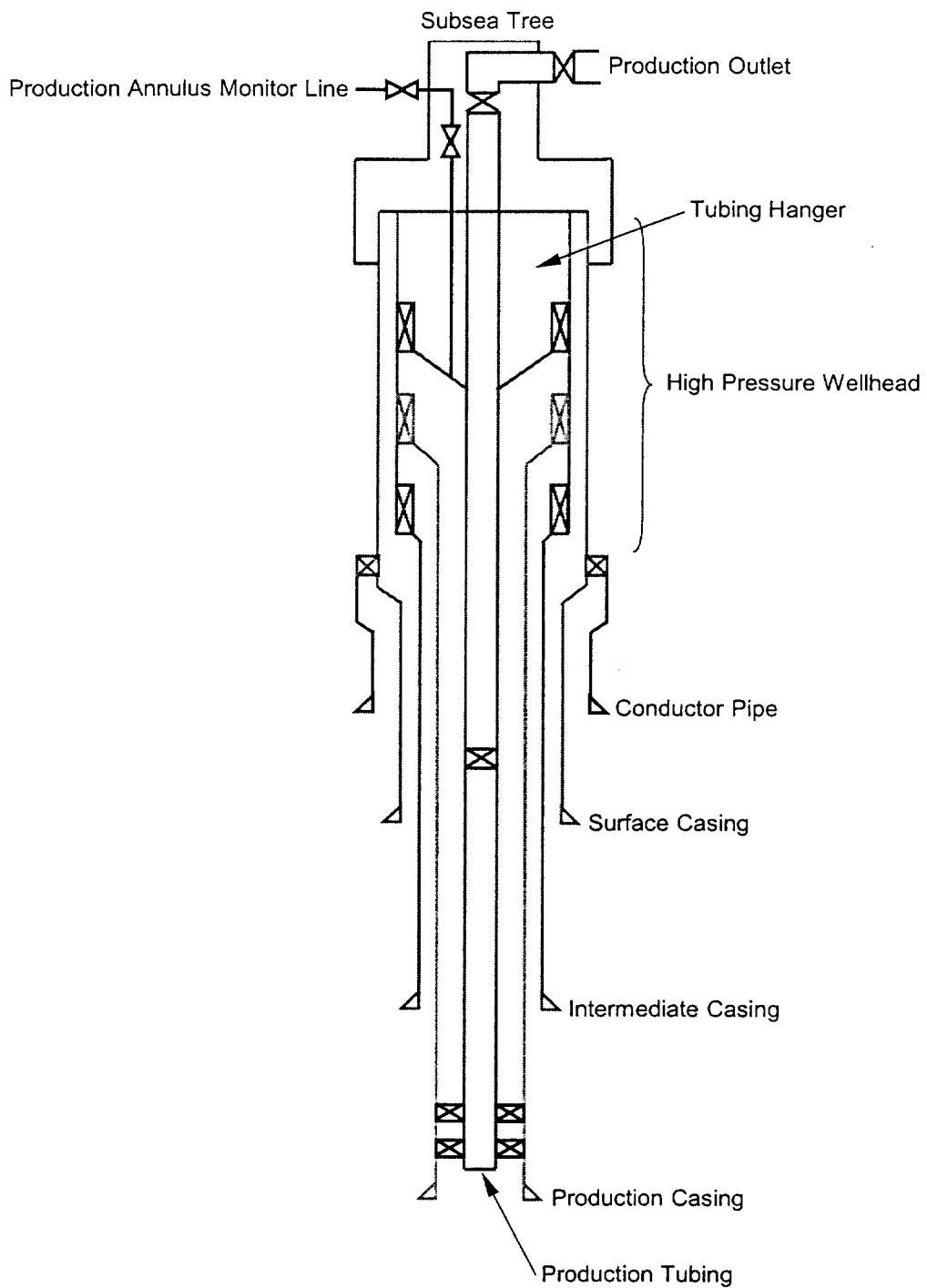
Figure 1: Current Practice

Figure 5: Wellhead Housing Side Outlets

Note: This concept is in direct violation of API Spec 17D Paragraph 1001.5b(1)(c) which states that “body penetrations within the [high pressure wellhead] housing are not permitted”. Penetrations through the non-retrievable, primary pressure and structural member of the subsea well foundation have not been considered an acceptable practice from a safety perspective.

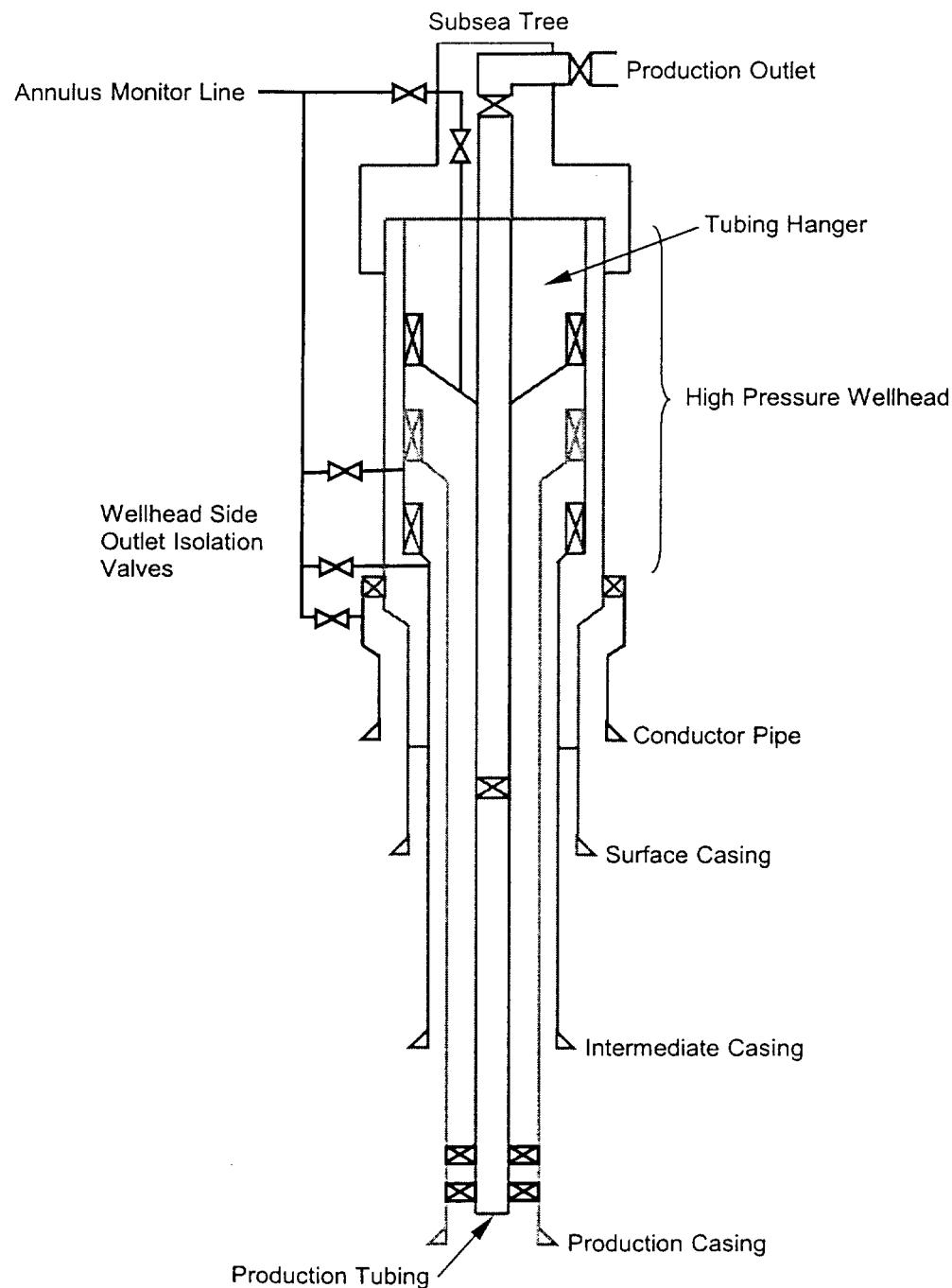


Figure 5a: Wellhead Housing Side Outlets Option Connected to Tree

